GAS TURBINES

Compliance Assistance Program
California Environmental Protection Agency
Air Resources Board

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Table of Contents

100 INTRODUCTION	
101 AIR RESOURCES BOARD	
102 COMPLIANCE ASSISTANCE PROGRAM	100 - 1
102.1 Target Audience	
103 MANUAL SCOPE AND ORGANIZATION	100 - 3
104 MAINTENANCE OF MANUAL	100 - 4
105 GENERAL DESCRIPTION	
106 GAS TURBINE APPLICATIONS	100 - 6
200 THEORY AND OPERATION	
201 SUBSTANCE PROPERTIES AND BASIC UNITS	
202 THE GAS TURBINE BRAYTON CYCLE	
202.1 Brayton Cycle Relationships	
202.1.1 The Actual Theoretical Brayton Cycle	
202.2 Effects of Operating Variables on Thermal Efficiency	200 - 10
203 SYSTEMS USED TO INCREASE GAS TURBINE PERFORMANCE	200 - 14
203.1 Regenerators	200 - 14
203.2 Intercoolers	200 - 16
203.3 Reheat	200 - 20
203.4 Effect of Regeneration, Intercooling and Reheating in Conjunction	200 - 22
204 ADDITIONAL GAS TURBINE PERFORMANCE PARAMETERS	200 - 22
204.1 Air Rate	200 - 22
204.2 Work Ratio	
204.3 Water Injection to Increase Performance	200 - 26
205 CLOSED GAS TURBINE CYCLE	200 - 26
205.1 Advantages and Disadvantages of Closed Cycle	200 - 28
206 BASIC COMPONENTS OF GAS TURBINES	200 - 29
206.1 Orientation of Gas Turbine Components	200 - 29
206.2 Compressors	
206.2.1 Positive Displacement Compressors	200 - 32
206.2.2 Centrifugal Compressors	
206.2.3 Axial Compressors	
Variable Stator Vanes	
Fixed Stator Vanes	
Axial/Centrifugal Compressor Comparison	200 - 41
206.3 Combustors	200 - 42
206.3.1 Combustor Performance	200 - 47
206.4 Turbine	200 - 48
206.4.1 Types of Turbines	200 - 48
206.4.2 Axial Turbines	200 - 49
Materials and Construction	
207 STATIONARY GAS TURBINE COGENERATION/COMBINED CYCL	Æ 200 - 52
207.1 Duct Burner Operation	
208 AIRCRAFT GAS TURBINES - JET ENGINES	200 - 58

208.1 Types of Jet Engines	200 - 59
208.1.1 Turbojet Engines	
208.1.2 Turbojet with Afterburner	
208.1.3 Turboprop Engine	
208.1.4 Turbofan Engine	
208.1.5 Ram Jet	
208.1.6 Rockets	
208.2 Aircraft vs. Industrial Gas Turbines	
•	
300 EMISSION CONTROL	
301 GAS TURBINE EMISSIONS	300 - 1
301.1 NOx Emissions	
301.1.1 Other Factors Affecting NOx Emissions from Gas Turbines	
301.1.2 NOx Effects on Health and the Environment	
301.2 Carbon Monoxide Emissions	
301.2.1 Carbon Monoxide Health Effects	
301.3 Sulfur Oxides (SOx)	
301.3.1 Sulfur Dioxide Health and Environmental Effects	
301.4 Hydrocarbon Emissions	
301.4.1 Ozone Health Effects	
301.5 Particulate Matter Emissions	
301.5.1 Particulate Matter Health Effects	
302 QUANTITY OF CALIFORNIA GAS TURBINE EMISSIONS	
303 NOX CONTROL SYSTEMS FOR GAS TURBINES	
303.1 Diluent Injection	
303.1.1 Water Treatment for Diluent Injection	
303.1.2 Examples of Diluent Injection Performance	
303.1.3 Water-In-Oil Emulsion Injection	
303.2 Selective Catalytic Reduction (SCR)	
303.2.1 SCR Catalysts	
303.2.2 Temperature Control for SCR	
en de la companya de	
303.2.3 Effects of Sulfur Compounds with SCR	
303.2.4 Ammonia Use	200 - 20
303.2.6 SCR Cost	
303.3 Selective Noncatalytic Reduction (SNCR)	
303.4.1 Lean Premixed Combustors	
303.5 Staged Combustor	300 - 40 200 - 47
303.6 Catalytic Combustion	
303.7 Duct Burner Emissions	
304 CARBON MONOXIDE EMISSION CONTROL	
305 STACK SAMPLING	
306 AIRCRAFT EMISSIONS	
307 ALTERNATIVE FUEL EMISSIONS	
307.1 Methanol	
ALC / 1 0011.00	41111 46

400 DECLIFATIONS	
400 REGULATIONS	400 1
401 FEDERAL REGULATIONS	400 - 1
401.1 Federal Clean Air Act	400 - 2
401.2 NSPS	400 - 2
401.2.1 Rule Applicability	400 - 2
401.2.2 Definitions	400 - 4
401.2.3 Standards for Nitrogen Oxides	400 - 3
Exemptions	400 - 7
401.2.4 Standards for Sulfur Dioxide	400 - 8
401.2.5 Monitoring of Operations	400 - 10
401.2.6 Test Methods and Procedures	
401.3 NESHAPS	400 - 11
401.4 Acid Rain Provisions	400 - 12
401.5 Title V Operating Permit Program	400 - 17
401.6 Prevention of Significant Deterioration (PSD)	400 - 17
402 STATE REGULATIONS	
402.1 California Clean Air Act	400 - 10
402.2 State Implementation Plan (SIP)	400 - 10
403 LOCAL (DISTRICT) REGULATIONS	400 - 10
403.1 District Stationary Gas Turbine Regulations	400 - 19
403.1.1 Exemptions	400 - 20
403.2 Visible Emissions	400 - 27
403.3 Sulfur Oxide Emissions	400 - 20
403.4 District Permits to Operate	400 - 29
403.5 Equipment Breakdown Provisions	400 - 30
403.6 Variances	400 - 27
403.7 New Source Review Rules	
403.7.1 BACT	400 - 38
403.7.2 Offsets	400 - 38
500 INSPECTION	
501 INSPECTION	500 - 1
501.1 Sequence of Inspection	500 - 2
501.1.1 Co-Current Approach	500 - 2
501.1.2 Counter-Flow Approach	500 - 3
501.1.3 Other Approaches	500 - 3
501.2 Levels of Inspection	500 - 3
502 PRE-INSPECTION PROCEDURES	500 - 4
502.1 File Review	500 - 4
502.2 Regulation Review	500 - 4
502.3 Equipment Check	500 - 5
502.4 Pre-entry and Entry	500 - 5
502.5 Pre-inspection Meeting	500 - 5
503 GAS TURBINE INSPECTION	500 - 6
503.1 Gas Turbine Visible Emissions (All Levels)	500 - 6
503.2 Gas Turbine General Physical Conditions	500 - 7

503.3 Gas Turbine Fuels	500 - 7
503.4 Time of Operation	500 - 8
503.5 Water or Steam Injection	
503.6 Ammonia Injection and SCR	500 - 9
503.7 CO Catalyst	500 - 9
503.8 Gas Turbine Emissions	500 - 11
504 POST-INSPECTION PROCEDURES	
APPENDICES A. References	A - 1
B. California Health and Safety Code	B - 1
GLOSSARY	
INDEX	

List of Figures

202.1	Simple Open Cycle Gas Turbine	200 - 5
202.2	Ideal Brayton Cycle	200 - 6
202.3	Actual Brayton Cycle T-S Diagram	200 - 9
202.4	Turbine Inlet Temperature vs. Thermal Efficiency	200 - 11
202.5	Pressure Ratio vs. Efficiency with Effect of Turbine Inlet Temperature	200 - 12
202.6	Thermal Efficiency vs. Pressure Ratio & Effect of Turbine and Compressor	200 - 13
	Thermal Efficiency vs. Pressure Ratio & Effect of Compressor Inlet Temp	
	Simple Open Cycle Gas Turbine with Regeneration	
	Actual Brayton Cycle T-S Diagram with Regeneration	
	P-V and T-S Diagrams Showing Isothermal Compression	
	Simple Open Cycle Gas Turbine with Intercooler and Regeneration	
	Ideal and Actual Cycle with Intercooling and Regeneration	
	Simple Open Cycle Gas Turbine with Intercooler, Regeneration and Reheater	
	P-V and T-S Diagrams of Actual Open Cycle with Reheating	
	Effect of Regeneration, Intercooling and Reheat on Efficiency	
	Air Rate vs Pressure Ratio with Effect of Turbine Inlet Temperature	
	Pressure Ratio vs. Work Ratio	
	Closed Cycle Gas Turbine	
	Various Open Cycle Gas Turbine Arrangements	
	Centrifugal Compressor	
	Centrifugal Compressor (Front View)	
	Centrifugal Compressor Impellers	
	LM 5000 Gas Turbine	
	Velocity and Pressure in Axial Compressor	
	Edge View of Axial Compressor & Stator Blades & Pressure Distribution	
	Fixed Stator, Axial Compressor Stages	
	Gas Turbine Combustors	
	O Silo Combustor	
	1 Combustor Liner and Air Flow	
	2 Impulse and Reaction Turbine Blades	
	Stationary Gas Turbine Cogeneration/Dual Cycle Power Plant	
	Top, Cross-sectional View of Duct Burner	
	Jet Engines	
	Single Spool Turbojet Engine	
	Afterburner Section of Gas Turbine	
	Turboprop Gas Turbine Engine	
	Turbofan Gas Turbine Engine	
	Ram Jet Engine Concept	
	NOx vs. Turbine Inlet Temperature	
	Thermal NOx vs. Equivalence Ratio	
	Carbon Monoxide vs. Turbine Inlet Temperature	
303.1	NOx, CO, and Unburned Hydrocarbons vs. Water Injection	300 - 22
	Effect of Water/Fuel Ratio on NOx, Thermal Efficiency and Power Output	

	Vanadium Pentoxide Catalyst Temperature vs. Water % NOx Removed	
	Lean Premix Combustor	
303.5	Annular Lean Premix Burner	300 - 42
303.6	Lean Premix Burner Modes	300 - 43
303.7	NOx and CO vs. Gas Turbine Load	300 - 45
	Staged Gas Turbine Combustor	
305.1	Stack Sampling System	300 - 52
~ ~~~	~	

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List of Tables

302.1	Stationary Gas Turbine Emissions	. 300 - 18
302.2	Jet Aircraft Commercial Emissions	. 300 - 18
302.3	Jet Aircraft Emissions - Military	. 300 - 19
302.4	Jet Aircraft Emissions - Civil	. 300 - 19
302.5	Uncontrolled NOx Emission Factors from Common Gas Turbines	. 300 - 20
303.1	NOx Reductions from Water and Steam Injection for Natural Gas Fuel	. 300 - 26
303.2	NOx Reductions from Water and Steam Injection for Distillate Oil Fuel	. 300 - 27
303.3	Typical NOx Reductions and Ammonia Slip from Various Gas Turbine Plants	. 300 - 38
	Duct Burner Emissions	
401.1	Determining F from Nitrogen Content of Fuel	400 - 6
401.2	Sulfur Dioxide Emission Limits for Gas Turbines	400 - 8
	Duration of Excess Emissions that Requires Reporting	
403.1	BAAQMD - Main Standards from Regulation for Gas Turbines	. 400 - 20
403.2	Mojave Desert AQMD - Main Standards from Regulation for Gas Turbines	. 400 - 21
403.3	Sacramento AQMD - Main Standards from Regulation for Gas Turbines	. 400 - 21
403.4	San Diego APCD - Main Standards from Regulation for Gas Turbines	. 400 - 22
403.5	SCAQMD - Main Standards from Regulation for Gas Turbines	. 400 - 22
403.6	SJVUAPCD - Main Standards from Regulation for Gas Turbines	. 400 - 23
403.7	Ventura County APCD Main Standards from Regulation for Gas Turbines	. 400 - 24
403.8	Yolo-Solano AQMD - Main Standards from Regulation for Gas Turbines	. 400 - 25
403.9	Relationship Between Light Transmission, Ringelmann and Opacity	. 400 - 28
403.1	0 Variances	. 400 - 34
503.1	Gas Turbine Inspection Form	. 500 - 10

Contents-vii

INTRODUCTION

101 AIR RESOURCES BOARD

The California Air Resources Board (CARB or ARB) was created by the California Legislature to control air pollutant emissions and to improve air quality throughout the State. Under direction of the California Environmental Protection Agency (Cal/EPA), the ARB works closely with the United States Environmental Protection Agency (EPA) and local air pollution control districts in improving air quality in California.

The CARB:

- Conducts inspections to ensure compliance with air pollution regulations;
- Develops rules and regulations to assist local air pollution control districts in their efforts to maintain air quality standards;
- Establishes air quality standards which identify acceptable concentrations of specific pollutants which are intended to protect the health of vulnerable members of the general population and to prevent property and crop damage;
- Monitors air quality throughout the State; and
- Evaluates the effectiveness of pollutant control strategies both for automobiles and industrial sources.

102 COMPLIANCE ASSISTANCE PROGRAM

The Compliance Assistance Program (CAP), created in 1988 by the ARB, assists local air pollution control districts in conducting more comprehensive, consistent, and accurate facility compliance inspections. The CAP program also provides industry with information and tools, in the form of self-help publications, which clarify compliance requirements and help explain how to stay in compliance with air pollution rules and regulations. The CAP also assists industries in establishing their own compliance inspection programs. By

ARB Responsibilities

June 1996 100 - 1

INTRODUCTION

conducting routine compliance inspections, industrial emissions sources can stay in compliance on a daily basis and can thereby avoid costly air pollution violations.

Through the development and distribution of rule-specific publications, the CAP creates an effective flow of information in a variety of useful formats. Based on the idea that sources will comply if they can understand what is required of them, CAP publications identify regulation requirements and present them in more readily readable formats.

Publications Formats

Publication formats include:

Handbooks. Easy to read, colorfully illustrated handbooks are developed for the industrial labor force and the interested public. Most can be read in ten minutes or less and most contain helpful self-inspection checklists.

Pamphlets. Quick reference pamphlets are filled with detailed flow charts, checklists and informative diagrams. These are designed for facility managers, plant personnel and industry's environmental managers.

Technical Manuals. Detailed technical inspection manuals are developed for local air pollution control district inspectors and industry's environmental managers. These contain rule information, process descriptions and step-by-step compliance inspection procedures.

Enforcement audits of certain industrial source types (such as solvent degreasers, gasoline vapor recovery systems, and coating of metal parts) show that noncompliance rates can be as high as 50 percent. Noncompliance results in excessive emissions.

Traditionally, ARB has sought to reduce noncompliance rates by providing an adequate deterrent through enforcement action against violators. In addition, ARB now seeks to reduce noncompliance rates and the associated excess emissions by ensuring that source operator knowledge includes:

- A basic understanding of the rules to which the source or product is subject; and

INTRODUCTION

- A basic understanding of how compliance is to be determined.

If California's nonattainment areas are to have any chance of achieving the ambient air quality standards, the excess emissions resulting from noncompliance must be reduced by air pollution control inspectors and industry personnel. Air pollution control inspectors can identify problems for the source operator and propose corrective action, but their periodic visits cannot ensure continuous compliance. Compliance is the job of educated source operators. The goal of the Compliance Assistance Program is thus twofold:

- To help air pollution control districts develop and maintain inspector knowledge; and
- To encourage industry to do self-inspections for continuous compliance.

102.1 TARGET AUDIENCE

This manual was written primarily for district field operation staff, district permitting staff, and environmental managers, but it may also be useful to other government agencies and industry personnel. It can be used as a reference manual or user's guide and it is designed for easy referencing, reading, and updating. It also contains graphics and illustrations to enhance understanding.

103 MANUAL SCOPE AND ORGANIZATION

After the introduction, this manual has a section on the theory and operation of gas turbines. After a brief discussion on the history and development of gas turbines, the basic theory of gas turbines and the Brayton cycle is discussed. The latter part of the Theory and Operation Section describes the main parts of the engine and how they work, and a brief section on the use of gas turbines for aircraft is included. Following the Theory and Operation Section is the Emission Control Section, where the manual shows what pollutants are created by gas turbines and how they are controlled. In the next section, Regulations, the manual describes the federal, state and district regulations that apply to gas turbines. After the Regulations Section is inspections. The Inspection Section describes how to inspect a gas turbine to determine compliance with air

CAP Goals

June 1996

INTRODUCTION

pollution regulations. Where applicable, health effects and characteristics of pollutants are discussed. The appendices include References, and applicable California Health and Safety Code Sections. The Glossary contains important terms from the manual; the Index at the end of the manual provides easy access to information.

104 MAINTENANCE OF MANUAL

The Compliance Assistance Program welcomes your comments concerning this manual. Your comments and corrections, changes in legal requirements, and new information on equipment and processes will be collected and periodically distributed in an upgrade packet. Only the manual users who return the tracking card located in the very front of the manual will receive an upgrade packet, so be sure to fill out your card and send it in as soon as you receive the manual.

105 GENERAL DESCRIPTION

Gas turbines are engines that work on a cycle similar to the reciprocating engines. In reciprocating engines, a combustible mixture of air and fuel are drawn into a cylinder through valves by a piston driven by a crankshaft. The valves close and the piston then compresses the air/fuel mixture. When the piston nears the top of the cylinder, a spark plug ignites the mixture. The rapid expansion of gases from combustion pushes the piston. The motion of the piston turns the crankshaft, performing work. When the cylinder rises again, valves open and the exhaust products are pushed out of the cylinder.

Instead of having a cylinder and piston, a gas turbine has a compressor rotor that compresses the air. Compressed air undergoes combustion in the combustor of a gas turbine. The expanding gases from combustion do work on a turbine instead of a piston.

The gas turbine has a more continuous process where compression, ignition, expansion and exhaust are conducted simultaneously, but in reciprocating engines these processes are conducted in a two or four stroke cycle. Both the gas turbine and the reciprocating engine can be used to create shaft horsepower, but the gas turbine can also be used to provide propulsion for aircraft using the exhaust gases exiting the turbine.

INTRODUCTION

Although reciprocating engines are most often called internal combustion engines, gas turbines are also internal combustion engines. Combustion engines can be classified as internal or external combustion engines. In gas turbines, the expansion of gases from combustion using atmospheric air turns a turbine to create the power for the engine. In a reciprocating engine, the expansion of gases from combustion drives a piston which then turns a shaft to create the power for the engine. On the other hand, in an external combustion engine the combustion occurs by using atmospheric air and a fuel, but another working fluid, such as steam, is used to transfer the energy from combustion to another location to produce mechanical power.

A good example of an external combustion engine is a steam engine. Combustion occurs in a boiler using air and fuel, but the heat from combustion in the boiler is used to boil water and produce steam. The steam is then used to drive a piston or turn a turbine to produce mechanical power.

The size of gas turbines in terms of power output generally ranges from 107 to over 268,000 horsepower [hp] (0.08 to over 200 megawatts [MW]). Groups of gas turbines are often installed in groups or "ganged" to meet power requirements.

The main advantages of gas turbine engines is that they can be installed relatively quickly and easily, no cooling water is required, they have lower capital costs than reciprocating and steam engines, and a high horsepower to weight ratio. Given the relative large output power capability of a gas turbine, it uses little space and is low in weight. This is why they work well as jet engines for aircraft.

Reciprocating engines compete with gas turbines depending on the application. Reciprocating engines require less fuel than gas turbines to produce the same horsepower, so their operating costs are lower. Gas turbines are not efficient at part load, but reciprocating engines can operate well at different loads. Capital costs, fuel costs, hours of operation, compatibility with existing equipment, operating experience and specific site data help determine the choice between a reciprocating engine and a gas turbine.

Internal Combustion Engines

External Combustion Engines

June 1996 100 - 5

INTRODUCTION

106 GAS TURBINE APPLICATIONS

Gas turbines are both stationary and mobile sources of air pollution; therefore, they are a stationary source of power or a power source for transportation. The shaft horsepower created by a gas turbine can be used to rotate generators to create electric power or run a variety of processes. Thrust or shaft horsepower can also be used for transportation. The following are some of the applications for a gas turbine:

Stationary gas turbines

- 1. Electric power generation at utilities Gas turbines can be used to turn generators to create electricity for homes, businesses, government, and industry. They also work well for providing extra electrical power on a seasonal basis, especially during the summer months when electrical demands are high from air conditioning. On a horsepower basis, electric utilities are the industry with the highest use of stationary gas turbines. The use of stationary gas turbines in electric utility power generation has recently increased due to decreased capital costs for gas turbines; increases in turbine efficiency; lower natural gas prices and proven reserves of natural gas; and financial, regulatory, legal and public opposition to nuclear power plants.
- 2. Cogeneration Facilities such as oil fields are likely to have gas turbines performing cogeneration. Gas turbines can be used to make steam that can be sent to produce electricity or perform other work. The Public Utility Regulatory Policies Act (PURPA) of 1978 requires electric utilities to purchase electric power from qualifying independent cogenerators of electric power. Electric utilities must also provide backup power to these cogenerators at reasonable rates. Gas turbines are unique in that they can generate two forms of energy (i.e. mechanical work for electrical power generation and steam for other processes) from one fuel source. Land fill gases and other waste gases may be mixed with natural gas to fuel gas turbines.
- 3. Oil industry/Petroleum refineries Refineries use a lot of energy and gas turbines are a type of engine that may be used to provide some power. Gas turbines can be used for cogeneration or as emergency power. It is important that refineries have a continuous reliable source of power to prevent upsets and other problems. Gas turbines can be used to run oil and gas extraction

INTRODUCTION

equipment. Since gas turbines can run on a wide range of fuels, from natural gas to crude oil, waste gases and residual oil, the recovered petroleum products provide an available fuel source. Gas turbines work well as sources of power in remote areas for the oil industry.

- 4. Industrial processes The power produced by gas turbines can be used for a variety of industrial processes. A few examples include: ethylene production, ammonia production, and liquefied natural gas production.
- 5. Natural gas compression and transport Natural gas is transported over large distances in North America. Natural gas compressor stations are used to compress natural gas to provide the necessary energy to move the gas down the pipeline. Gas turbines are used to power the natural gas compressors.
- 6. Power for offshore oil platforms Gas turbines can provide electrical or mechanical power for the platform. They may also run oil and gas extraction equipment.
- 7. Backup and emergency power Gas turbines can be used as a source of emergency electrical power for hospitals, telephone companies and other industries. These engines generally only operate between 75 and 200 hours per year and are small in size (under 5000 hp). Gas turbines work well in this capacity because of their small size, reliable starting and relatively low maintenance, but reciprocating engines are usually used, especially in applications under 2,700 hp.²

Transportation

- 1. Aircraft propulsion Jet engines are used on most commercial airlines, military and other government aircraft. They are also used to power private aircraft.
- 2. Propulsion for ships Gas turbines are used to power many of the Navy's destroyers, patrol boats, cruisers and some larger ships. Some cargo ships, yachts, catamarans, and high speed hydrofoils also use gas turbines. Gas turbines are a large improvement over the big, heavy, dirty boilers that powered ships in the past.

June 1996 100 - 7

INTRODUCTION

3. Propulsion for helicopters - All of today's modern helicopters are powered by gas turbines. The gas turbine's low weight relative to its high output power and its high reliability make it a good engine for helicopters.

100 - 8 June 1996

THEORY & OPERATION

Gas Turbines

Long ago scientists began developing the fundamentals of the gas turbine within their minds. In 130 B.C. Hero of Alexandria was the first person known to have built a gas turbine that encompasses the basic concepts of modern engines. Although this was a great accomplishment, actual progress toward creating a working gas turbine did not occur until nearly 1800.

In the early 1800's, Stirling and Ericsson developed hot air engines that led to the creation of the Stirling constant volume cycle and Ericsson constant pressure cycle. Both of these engines utilized isothermal (constant temperature) compression and expansion. In the mid 1800's Joule proposed a constant pressure cycle using isentropic compression and expansion. The current fundamental gas turbine cycle used today is the one created by Joule. It utilizes both isentropic compression and expansion. This cycle is called the Joule or Brayton cycle.

In 1872, the first approach to making a modern working gas turbine was made by Dr. F. Stolze. The Stolze gas turbine was equipped with a multistaged axial compressor, an externally fired combustion chamber, and a reaction turbine. The unit was tested between 1900 and 1904 but it never operated successfully, due to a lack of knowledge of aerodynamics, and because materials that could handle high temperatures and stresses were not yet available.

In 1902, the first operating gas turbine in the U.S. was developed by Mr. Charles Curtis and Dr. S. A. Moss at Cornell University. The problem with the device was that it consumed more energy than it produced. This gas turbine used a steam driven compressor to supply compressed air for combustion.

The development of more efficient compressors by Rateau led to the first version of a gas turbine that created positive work. Between 1903 and 1906 a gas turbine was created by the "Societe des Turbomotoeurs" in Paris, with a thermal efficiency between 2 to 3%.² This engine had a multistaged centrifugal compressor and operated with a cycle similar to modern gas turbines.

From 1905 to 1930 a large amount of successful research and development was conducted in the areas of aerodynamics, metallurgy, turbo-supercharging and other fields, which contributed greatly to the development of the gas turbine. By 1935, the development of practical gas turbines was achieved. In the late 1930's the Navy became interested in the possible applications of gas turbines. World War II then led to accelerated research and development of the gas turbine.

1st U.S. Gas Turbine

1st Gas Turbine with Positive Output

June 1996 200 - 1

THEORY & OPERATION

201 SUBSTANCE PROPERTIES AND BASIC UNITS

Mass

In English units, the unit for mass is the pound-mass (lbm). From Newton's law: $(F = [m/g_a]a)$

where:

F = force (lbf)

m = mass (lbm)

 $gc = gravitational constant 32.2 (lbm-ft)/(lbf-sec^2)$

 $a = acceleration due to gravity 32.2 ft/sec^2$.

From the above equation, the difference between pounds (lbs.), which is more accurately termed as pounds-force (lbf) in fields of air pollution, science and engineering, and lbm can be seen. Although (lbm) and (lbf or lbs.) will be the same numerically because the two 32.2's cancel, they have different units.

Pressure

Pressure is usually measured by pounds per square inch (psi) or pounds per square foot (psf). Other units include atmospheres (1 atm = 14.7 psi), inches of water (1 atm = 407.1 inches of water), torr (1 atm = 760 torr), millimeters or inches of mercury (1 atm = 760 millimeters of mercury) and millibars.

Standard Temperature and Pressure (STP) is used to standardize the pressure and temperature of systems. STP is defined as one atmosphere at 32, 60, 68, or 70 degrees Fahrenheit. STP makes it easier to accurately compare parameters for gases between different systems, such as flow rates.

Temperature

The temperature of a substance is a thermodynamic property that depends on the substance's energy content.³ Heat energy usually flows from a hot object to a cold one.

The units of temperature are Fahrenheit in the English system and Celsius in the SI system. The absolute temperature scale should be used for calculations unless a temperature difference is required. In the English system the Rankine scale is used. Absolute zero is zero degrees Rankine (-459.67 degrees Fahrenheit), and zero degrees Kelvin (-273.15 degrees Celsius).

STP

Density and Specific Volume

Density (ρ) is mass per unit volume - i.e. lbm/ft³. Specific volume (v) is simply the reciprocal of density (v = $1/\rho$).

Internal Energy

Internal energy (U or u) is all of the potential and kinetic energy possessed by a substance. Internal energy is a function of temperature. As the temperature of a system increases the internal energy increases. Internal energy is usually in Btu/lbm or Btu/pmole, where "u" indicates Btu/lbm and "U" indicates Btu/pmole. The term Btu (British Thermal Unit) is a unit of energy approximately equivalent to a burning match.

Enthalpy

Enthalpy (H or h) is a property that represents the total useful energy in a substance.⁴ These substances often include steam or hot air. Enthalpy consists of two parts, internal energy and flow energy.

h = u + pv/J (Btu/lbm)

H = U + pV/J (Btu/pmole)

where:

 $V = \text{volume (ft}^3)$

 $v = \text{specific volume (ft}^3/\text{lbm})$

J = Joule's constant (778 ft-lbf/Btu)

U and u = internal energy (Btu/lbm and Btu/pmole respectively)

The "pv or pV" term is the flow energy.

Entropy

Entropy (S or s) is the amount of energy that is no longer available to do work. It also characterizes the disorder or randomness of a system.

Specific Heat

Different substances require different amounts of heat to attain a specific change in temperature. The ratio between the heat to the temperature change is the specific heat.⁵

THEORY & OPERATION

 $c = Q/(m\Delta T) (Btu/lbm-{}^{\circ}R)$

where:

m = mass (lbm)

Q or q = heat transfer (Btu) or (Btu/lbm)

 ΔT = temperature change

c or $C = \text{specific heat (Btu/lbm-}^{\circ}R)$ or (Btu/pmole- $^{\circ}R$)

The Brayton cycle is one of the air standard cycles (power cycles that include the Otto cycle for reciprocating internal combustion engines and the diesel cycle) and the working fluid is air, but the specific heat of gases depends on its conditions. The specific heats used to identify gases are constant volume (c_v) and constant pressure (c_s) specific heats.

Therefore for gases:

 $Q = mc_{\cdot}\Delta T$ (constant volume process) and

 $Q = mc_n \Delta T$ (constant pressure process)

The ratio of the specific heats for gases is defined as "k."

 $k = c_{p}/c_{y}$

"k" for air is typically 1.4.

202 THE GAS TURBINE BRAYTON CYCLE

Air Standard Cycles

The Brayton cycle or Joule cycle is a cycle that is one of a number of existing air standard combustion cycles. The main air standard cycles include the Otto cycle for the reciprocating internal combustion engine; the diesel cycle for the diesel engine; the dual cycle, which is a combination of the Otto cycle and diesel cycle; the Brayton cycle for gas turbines; the Ericsson cycle and the Stirling cycle.

The Brayton cycle differs from the most common combustion cycles (the Otto and diesel cycle) in that air flow and fuel injection are steady, and the parts of the cycle occur within different equipment. In the Otto and diesel cycles, fuel and air are injected into a cylinder at specific times before the piston reaches top dead center. In the gas turbine fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the engine and compressed by the compressor. Unlike the Otto cycle, all the parts of the Brayton cycle occur simultaneously in a gas turbine. Figure 202.1 illustrates the basic orientation of the main equipment in a simple open cycle gas turbine.

THEORY & OPERATION

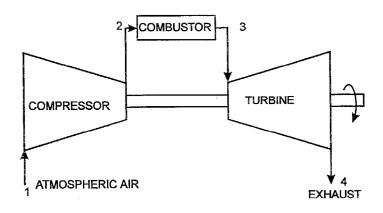
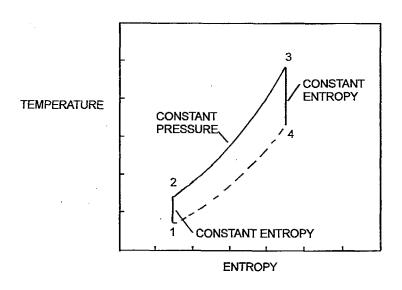


Figure 202.1 Simple Open Cycle Gas Turbine

From 1 to 2, atmospheric air enters the compressor of a gas turbine and ideally goes through an isentropic (constant entropy, i.e. no energy loss) compression (Fig 202.1 and 202.2). An isentropic process has no heat transfer. Figure 202.2 illustrates the ideal Brayton cycle pressure-specific volume and temperatureentropy property plots. From 2 to 3, fuel is added to the compressed air and ignited. The temperature of the gas in the combustor rises rapidly up to point 3. The process from 2 to 3 is ideally constant pressure with addition of heat. It can be seen from the pressure-specific volume plot that the pressure in the ideal Brayton cycle from 2 to 3 is constant. In the next stage, from 3 to 4, the hot gases go through an isentropic (constant entropy, i.e. no energy loss) expansion through the turbine. The energy of the gas is transferred to the turbine and the pressure and the temperature of the gas decrease. The mechanical energy of the turbine can be used to perform work i.e. turn a generator to create electricity. Unfortunately, about 75% of the output power of the turbine must be used to drive the compressor which compresses the air for the engine. From states 4 to 1, hot gases are released from the turbine. This process is ideally constant pressure with rejection of heat to a heat sink, where the heat sink is the atmosphere. In a closed gas turbine cycle, the gases exiting the turbine are returned to the compressor. Practically all gas turbines operate on a open cycle. On the pressure-specific volume and temperature-entropy plots in the open cycle, the process from states 4 to 1 is shown as a dashed line, since the working fluid is exhausted to the atmosphere and clean air is drawn into the compressor.

June 1996 200 - 5

THEORY & OPERATION



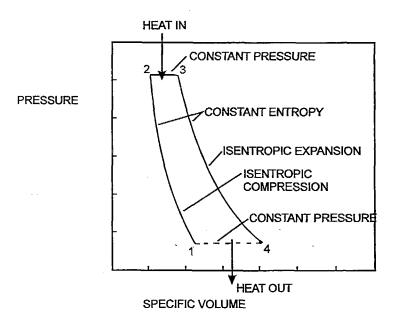


Figure 202.2 Ideal Brayton Cycle

The main assumptions that are made with the ideal Brayton cycle are:

- -The working fluid is air, which is considered to be totally dry with variable specific heats.
- -The air is considered to be an ideal gas.
- -The air is considered to have the same composition throughout the cycle.
- -There are no pressure drops in the system.
- -There are no heat transfer or leakage losses.
- -Potential energy and kinetic energy changes are negligible.
- -The weight of the fuel added in the system is negligible compared to the weight of the air used by the engine.

202.1 BRAYTON CYCLE RELATIONSHIPS

A number of different relationships can be developed to compute the work, heat transfer, temperatures, pressures, efficiencies, and mass flow rates for gas turbines. These equations and the derivations of them can be found in almost any thermodynamics textbook. Some of these relationships are illustrated here.

$$w_c = c_p(T_2-T_1) = h_2-h_1$$

 $w_c = Ideal \text{ work required for compressor (Btu/lbm of air)}$

$$W_t = c_p(T_3 - T_4) = h_3 - h_4$$

 $W_t = Ideal$ work produced by turbine (Btu/lbm)

$$q_{in} = c_p(T_3 - T_2) = h_3 - h_2$$

 $q_{in} = Ideal$ amount of energy input by combustor (Btu/lbm)

$$\begin{split} &\eta_{th} = (q_{in} \text{-} q_{out})/q_{in} = [(h_3 \text{-} h_2) \text{-} (h_4 \text{-} h_1)]/(h_3 \text{-} h_2) \text{ also:} \\ &\eta_{th} = (w_t \text{-} w_c)/q_{in} = [(h_3 \text{-} h_4) \text{-} (h_2 \text{-} h_1)]/(h_3 \text{-} h_2) \end{split}$$

where

 η_{th} = The thermal efficiency (analogous to fuel economy) of the gas turbine

$$\begin{split} & \text{If} = c_p \text{ is constant} \\ & \eta_{\text{th}} = [(T_3 \text{-} T_2) \text{-} (T_4 \text{-} T_1)] / (T_3 \text{-} T_2) \end{split}$$

THEORY & OPERATION

Pressure Ratio

Another term that is used to quantify gas turbine performance is the **pressure** ratio, R_p . The pressure ratio is defined as the pressure exiting the gas turbine compressor divided by the pressure entering the turbine compressor.

$$R_p = p_2/p_1$$

Compression Ratio

This value is analogous to the **compression ratio** which is used to quantify performance in an Otto cycle (reciprocating) engine. The compression ratio is different in that it is a ratio of the volume of the cylinder at bottom dead center divided by the volume of the cylinder at top dead center.

$$R_c = V_1/V_2$$

The pressure ratio can also be utilized to calculate the ideal thermal efficiency in the gas turbine Brayton cycle.

$$\eta_{th} = 1 - (1/R_p)^{(k-1)/k}$$

202.1.1 The Actual Theoretical Brayton Cycle

In the ideal Brayton cycle the compressor and turbine efficiencies are considered to be 100% and the compressions and expansions are isentropic. In the real world efficiencies are not 100% and the compressions and expansions are not isentropic. In the actual theoretical cycle, there are friction losses in the compressor and turbine. In the actual theoretical Brayton cycle the assumptions concerning the fluid being an ideal gas, the specific heats being variable, no leaks in the system, potential and kinetic energy losses are negligible etc. (Section 202) are still valid. The actual theoretical Brayton Cycle is more similar to the operating cycle of actual, real world gas turbines, but other inefficiencies further distort the cycle shown in Figure 202.3. Some other inefficiencies include heat, pressure, and kinetic energy losses.

The actual work required for the compressor in the actual theoretical cycle is from 1 to 2'. Note that the enthalpy at 2' is higher than the enthalpy at 2. Therefore, more work is required to run the compressor under non-ideal conditions and more energy is required to reach state 2'. Also the entropy from 1 to 2' is not constant and is non-isentropic.

THEORY & OPERATION

Gas Turbines

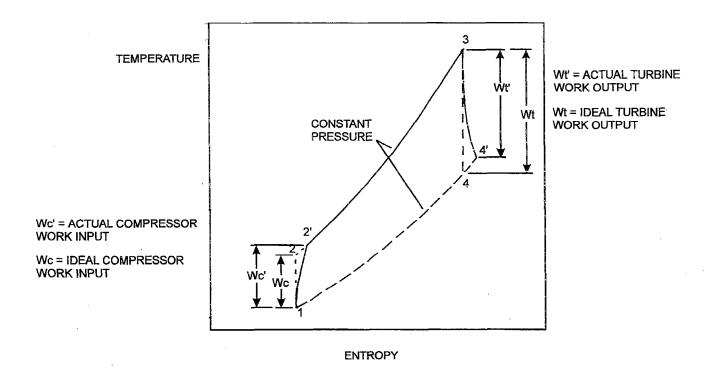


Figure 202.3 Actual Brayton Cycle T-S Diagram

$$w'_c = h'_2 - h_1 = Actual compressor work required $h'_2 = h_1 + (h_2 - h_1)/\eta_c$ where:$$

 η_c = Compressor efficiency = w_c/w_c^\prime = ideal compressor work/actual compressor work

$$q_{inac} = h_3 - h'_2$$

 $q_{inac} = Actual energy input by combustor (Btu/lbm)$

The actual work output from the compressor is from 3 to 4'. The enthalpy at 4' is higher than the enthalpy at 4, so less net energy is output by the turbine. As with the compressor cycle, the entropy is not constant and non-isentropic.

 $w'_{1} = h_{3} - h'_{4} = Actual output work produced by turbine$

THEORY & OPERATION

 $h'_4 = h_3 - (h_3 - h_4) \eta_t$

where:

 η_t = Turbine efficiency = w', w_t = actual turbine work produced/ideal turbine work produced

The actual thermal cycle efficiency is:

$$\eta_{th} = (w'_t - w'_c)/q_{inac} = [(h_3 - h'_4) - (h'_2 - h_1)]/(h_3 - h'_2)$$

202.2 EFFECTS OF OPERATING VARIABLES ON THERMAL EFFICIENCY

The thermal efficiency of an actual open gas turbine cycle is heavily affected by the following variables:

- 1. Turbine inlet temperature (T₃)
- 2. Pressure ratio (R_p)
- 3. Turbine efficiency (η,)
- 4. Compressor efficiency (η_c)
- 5. Compressor inlet temperature, (T_1)

Turbine inlet temperature

As the inlet temperature into a turbine is increased, the thermal efficiency increases (Fig. 202.4).⁶ Note that the thermal efficiency vs. turbine inlet temperature (T_3) curve is with a compressor efficiency of 0.85 (85%) and a turbine efficiency of 0.90 (90%).

Unfortunately, the inlet temperature into a gas turbine is limited by the type of material used in the turbine. The practical limit to increasing the temperature is the ability of the turbine to withstand the high rotative and heat stresses it is subjected to. Advancements in metallurgy have allowed the use of higher inlet temperature over time since the creation of the gas turbine. Most simple cycle gas turbines have a thermal efficiency between 30 and 35%. Some of today's most efficient gas turbines can attain a thermal efficiency as high as 40%.⁷

Simple Cycle Efficiency

Pressure ratio

The effect on thermal efficiency from pressure ratio and turbine inlet temperature with other variables held constant is illustrated by Figure 202.5.8 The curves with the highest turbine inlet temperatures have a higher efficiency.

THEORY & OPERATION

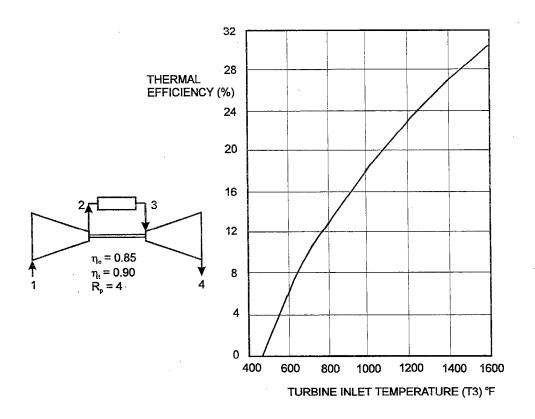


Figure 202.4 Thermal Efficiency vs. Turbine Inlet Temperature

The top two curves with the higher temperatures have higher efficiencies as the pressure ratio is increased. The other curves have a peak pressure ratio for the highest thermal efficiency. Also note that Figure 202.5 is from a simple open gas turbine with a compressor and turbine efficiency of 0.80 (80%) and a compressor inlet temperature (atmospheric temperature) of 60°F.

Compressor and turbine efficiency

The higher the efficiency of the compressor and turbine in a gas turbine, the higher the thermal efficiency will be. Figure 202.6 illustrates a plot of thermal efficiency vs. pressure ratio, with different compressor and turbine efficiencies. The top curve on the diagram (dashed line) represents the ideal gas turbine cycle with compressor and turbine efficiencies being 100%. Each curve has an optimum pressure ratio for the highest thermal efficiency and as the efficiency of the compressor and turbine drop, the optimum pressure ratio also drops.

June 1996 200 - 11

THEORY & OPERATION

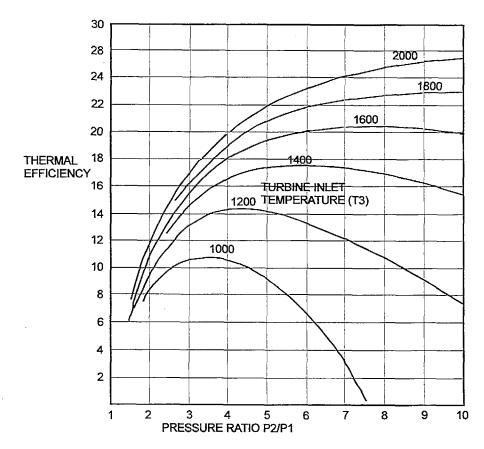


Figure 202.5 Thermal Efficiency vs. Pressure Ratio with Effect of Turbine Inlet Temperature

Compressor inlet temperature

As the inlet temperature to the compressor of a gas turbine is lowered, the thermal efficiency increases (Fig. 202.7).¹⁰ In the thermal efficiency vs. pressure ratio plot, as the compressor inlet temperature is lowered the peak pressure ratio is higher.

Since lower compressor inlet temperatures improve efficiency, stationary gas turbines tend to run more efficiently in the winter.

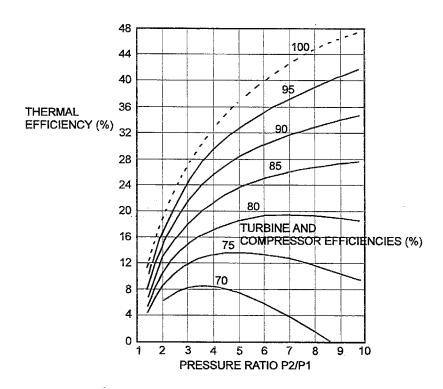


Figure 202.6 Thermal Efficiency vs. Pressure Ratio with Effect of Turbine and Compressor Efficiencies

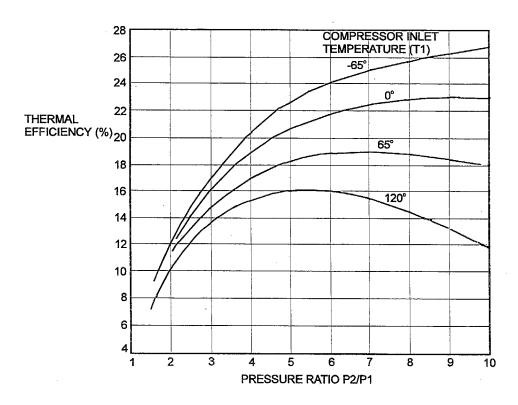


Figure 202.7 Thermal Efficiency vs. Pressure Ratio with Compressor Inlet Temperature

THEORY & OPERATION

203 SYSTEMS USED TO INCREASE GAS TURBINE PERFORMANCE

203.1 REGENERATORS

Regenerators or recuperators are basically heat exchangers that utilize energy from the exhaust of the gas turbine to improve efficiency. A simple cycle gas turbine utilizing a regenerator is called the regenerative cycle. The general orientation of a regenerator relative to the other equipment in a gas turbine is shown in Figure 203.1.

Hot exhaust gases from the turbine enter the regenerator from the "hot side" of the regenerator while cooler air from the compressor enters the "cold side" of the regenerator. The hot gases circulate around tubes or plates that contain the air from the compressor. Heat energy is transferred from the hot gases to the cooler compressed air across the tubes or plates in the regenerator. Since the temperature of the compressor air from the regenerator is higher, less energy input (less fuel) is required in the combustor to raise the gases to the turbine inlet

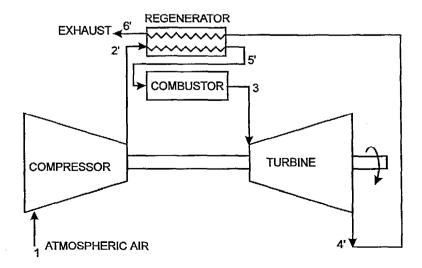


Figure 203.1 Simple Open Cycle Gas Turbine with Regeneration

THEORY & OPERATION

Gas Turbines

temperature (T_3) . The regenerator does not affect the work required for the compressor or the output work of the turbine, but it increases the thermal efficiency of the cycle.

The regenerator must be carefully designed so that pressure drops across it are not excessive. High pressure drops can eliminate the gains attained in thermal efficiency. A regenerator must also be built to withstand large temperature changes. Regenerators are generally unsuitable for aircraft because of the regenerator's weight and large size. Since stationary gas turbines are often derivatives of aircraft engines, most stationary gas turbines do not have regenerators. Furthermore, the regenerative cycle is typically not economically viable with newer gas turbines because the high cost of the regenerators and other equipment does not make up the savings in improved fuel economy.

The ideal open cycle with regeneration is shown as states 1-2-5-3-4-6-1 (Fig. 203.2). In order for regeneration to be possible, the temperature at the turbine exit (T_a) must be greater than the temperature at the compressor exit (T_a) . Figure

Regenerative Cycle

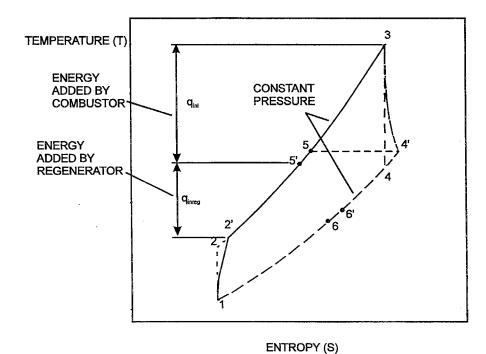


Figure 203.2 Actual Brayton Cycle T-S Diagram with Regeneration

-15

THEORY & OPERATION

203.2 also illustrates the actual open Brayton cycle with regeneration (1-2'-5'-3-4'-6'-1). As stated earlier, the actual cycle contains non-ideal compressor cycles and non-ideal turbine expansions.

In the real world, regenerators for gas turbines are at least 75% efficient. In order to reach an ideal efficiency of 100%, the temperature of the compressed air leaving the compressor (T'₂) would have to be raised to the temperature of the exhaust gases leaving the turbine (T'₄). The regenerator would have to have an infinite surface area in order to have a 100% efficiency.

The efficiency of an actual regenerator is:

$$\eta_{regac} = (h'_5 - h'_2)/(h'_4 - h'_2)$$

The main factors that are used to design the regenerator include: space limitations, maintenance issues, cleaning restrictions, manufacturing limitations, desired effectiveness and pressure losses. As stated earlier, the pressure drops must be kept as low as possible. Large pressure drops on the cold side of the regenerator handling the compressor air increases the compressor work. Large pressure rises on the hot side of the regenerator increases turbine back pressure and decreases turbine output.

The energy added to the compressed air in the actual regenerator is:

$$q_{inreg} = (h'_4 - h'_2)\eta_{regac} = h'_5 - h'_2 (Btu/lbm)$$

The energy added by the combustor with an actual regenerator is: $q_{inl} = h_3 - h'_5$ (Btu/lbm)

The efficiency of the actual open cycle with regeneration is:

$$\eta_{th} = (w_t - w_c)/q_{inl} = [(h_3 - h_4) - (h_2 - h_1)]/(h_3 - h_5)$$

203.2 INTERCOOLERS

Intercooling is a method used to reduce the compressor work of a gas turbine with multipule compressors by cooling the air as it flows from one compressor to another. By reducing the compressor work, the net work of the entire gas turbine cycle will be higher. Intercooling generally does not have a large effect on the thermal efficiency.¹¹

THEORY & OPERATION

Gas Turbines

In the ideal cycle the isentropic compression cycle from 1 to 2 is replaced by an isothermal (constant temperature) process 1-i-2 (Fig. 203.3). The work of compression is reduced by the "amount" of the shaded area in the P-v diagram. Since the area of the whole cycle is increased with intercooling, because the cycle goes 1-i-3-4 instead of 1-2-3-4, the work of the gas turbine is increased. The output work from the turbine from 3 to 4 is still the same, but the net work of the entire cycle is increased by the shaded area.

Intercooling Cycle

Isothermal compression is not practical, so a multiple compressor system with an intercooler is used (Fig.203.4). The more compressors and intercoolers that are used, the closer the entire compressor cycle comes to isothermal compression. Physical limitations usually limit gas turbines to two compressors and one intercooler.

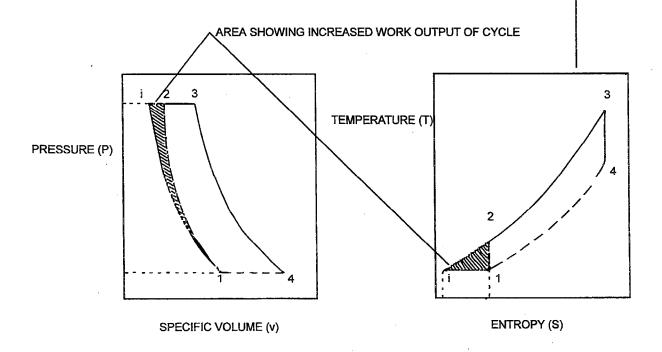


Figure 203.3 P-v and T-s Diagrams Showing Isothermal Compression

June 1996 200 - 17

THEORY & OPERATION

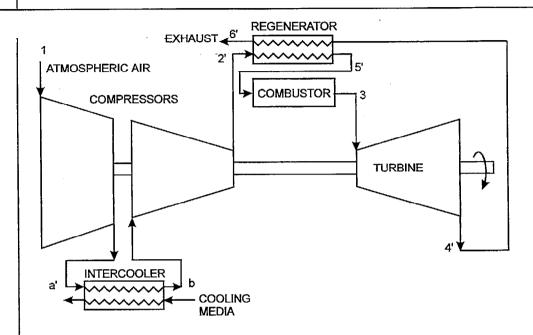


Figure 203.4 Simple Open Cycle Gas Turbine with Intercooler and Regeneration

In the ideal cycle, replacing the isentropic compression cycle with an isothermal compression cycle only increases the thermal efficiency by less than 1% when the gas turbine is operated with pressure ratios less than 16 to 20.¹² The increase in net work from intercooling is decreased by the increase in energy required for the combustor to raise the temperature of the air stream from "i" to 3 instead of from 2 to 3. The air is colder and more energy is required to heat it with the intercooler, but this disadvantage is reduced if the intercooler is used in conjunction with a regenerator.

Figure 203.5 illustrates both the ideal and actual open cycles for a gas turbine with an intercooler and regeneration, where 1-a-b-2-5-3-4-6-1 is the ideal cycle and 1-a'-b-2'-5'-3-4'-6'-1 is the actual cycle. The area of this cycle is less the "ideal" cycle with isothermal compression (Fig. 203.3), but it is still greater than the area of the cycle without intercooling, so the work output with intercooling is theoretically higher. The first compressor is from 1 to "a" for the ideal cycle, and 1 to a' for the actual cycle. Again, note that for the ideal compression cycle entropy is constant (from 1 to "a"), and that in the actual cycle the compression from 1 to a' is non-isentropic and requires more work. From "a" or a' to "b" the

Gas Turbines

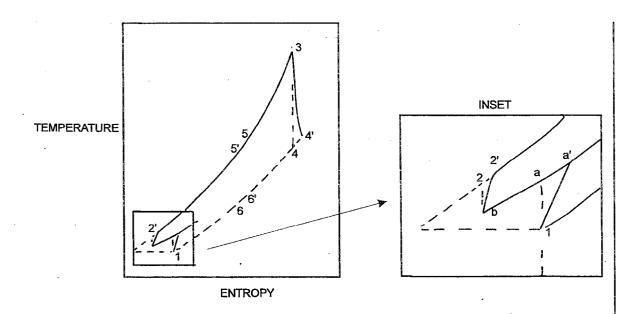


Figure 203.5 Ideal and Actual Cycle with Intercooling and Regeneration

air flows through the intercooler and the temperature drops. The pressure also theoretically remains constant across the intercooler in both the ideal and actual cycles. The next compression occurs in the second compressor in a similar manner from "b" to 2 in the ideal cycle and "b" to 2' in the actual cycle.

The total compressor work for the actual cycle with intercooling is:

$$wc' = wc'_{1} + wc'_{2}$$

$$wc' = [(h_{a}' - h_{1}) + (h_{2}' - h_{b})]$$

$$wc' = [(h_{a} - h_{1}) + (h_{2} - h_{b})]/\eta_{c}$$

The efficiency of the intercooler is (for the actual cycle): $\eta_{int} = (h_a' - h_b)/(h_a' - h_1)$

Intercoolers have many of the limitations of regenerators. In reality, intercooling is generally not economical, but it is common for the air entering the engine to be cooled before it enters the compressor. Cooling the air makes it denser, therefore more air enters the engine, combustion is improved, and more power can be produced.

THEORY & OPERATION

203.3 REHEAT

Reheating increases the work output of a turbine in a gas turbine power plant. The hot gases expanding through the turbine are made to approach an isothermal (constant temperature) process instead of a constant entropy process. Reheating in a gas turbine is analogous to the intercooler previously described in Section 203.2, except an intercooler is used to decrease the amount of compressor work required.

A reheater works by taking the hot gases that have been partially expanded through a turbine, reheating the gases to the maximum permissible turbine inlet temperature, and expanding them through another turbine (Fig. 203.6).

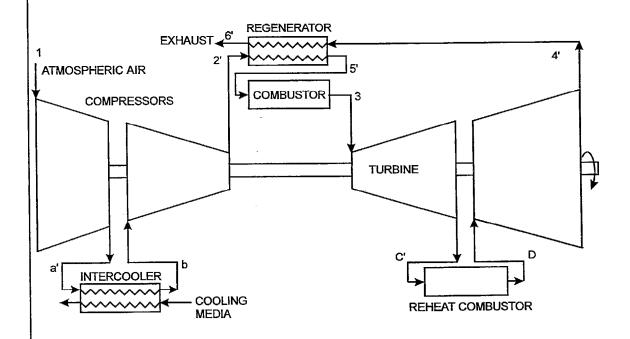


Figure 203.6 Simple Open Cycle Gas Turbine with Intercooler, Regeneration and Reheater

Gas Turbines

Figure 203.7 illustrates a pressure vs. specific volume and a temperature vs. entropy diagram of the actual Brayton cycle with a reheater. Hot gases are expanded through the first turbine from 3 to C'. During the process from C' to D, gases are reheated in a reheating combustion chamber. Then from D to 4' hot combustion gases are expanded through the second turbine, transferring more mechanical energy to the rotating turbine. The increase in output work from the turbine is indicated by the shaded area (C'-D-4'-X). When the gas turbine has reheat the cycle goes 1-2'-3-C'-D-4'-X-1, and the area of this cycle is larger than the cycle without reheat (1-2'-3-X-1).

Reheat Cycle

As with an intercooling, reheating in a gas turbine has little effect on the overall efficiency of the gas turbine cycle. Increases in efficiency that could be attained by the increase in output work from reheating are negated by the increase in energy input in the combustor. Figure 203.7 illustrates that the temperature of the gases exiting the second turbine at 4' is higher than the temperature of the gases would be without reheating at X. This works well for regeneration, since more heat will be able to be transferred from the combustion gases to the air exiting the compressor.

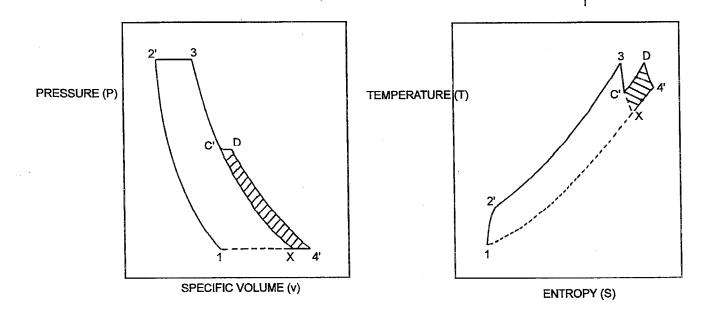


Figure 203.7 P-v and T-s Diagram of Actual Open Cycle with Reheating

THEORY & OPERATION

Reheating is not done in real world stationary gas turbines, but afterburners for jet aircraft operate similar to reheaters.

203.4 EFFECT OF REGENERATION, INTERCOOLING AND REHEATING WHEN USED IN CONJUNCTION

Although regeneration, intercooling and reheating are generally impractical due to the additional weight, cost, and complexity of a gas turbine, applications of these systems can be used to increase the performance of today's engines.

Figure 203.8 illustrates how each of the different systems improve thermal efficiency. Improving thermal efficiency is basically the same as improving fuel economy. Curve "B" shows a gas turbine with a regenerator. The addition of a regenerator substantially increases the efficiency. Intercooling and reheat by themselves have a small effect on thermal efficiency. Intercooling and reheat help improve the performance of the gas turbine at part load. With increasing turbine inlet temperatures, the thermal efficiency of all the systems increases. As expected, the gas turbine with no additional elements (curve A) has the lowest efficiency. The highest efficiency (curve E) occurs when the gas turbine uses a regenerator, intercooler and reheat with the highest temperature possible.

204 ADDITIONAL GAS TURBINE PERFORMANCE PARAMETERS

204.1 AIR RATE

The air rate is the ratio of the mass flow rate of air through a gas turbine to the net horsepower output of the gas turbine. The units of air rate are typically (lbm/hp-hr) where the mass flow rate of air is lbm/hr (pound-mass of air per hour) and the net output of the gas turbine is horsepower (hp). The net output of the gas turbine is the difference between the output work of the turbine and the work required to run the compressor.

The reciprocal of the air rate is the specific power. Sometimes the specific power of a gas turbine is used to rate a gas turbine.

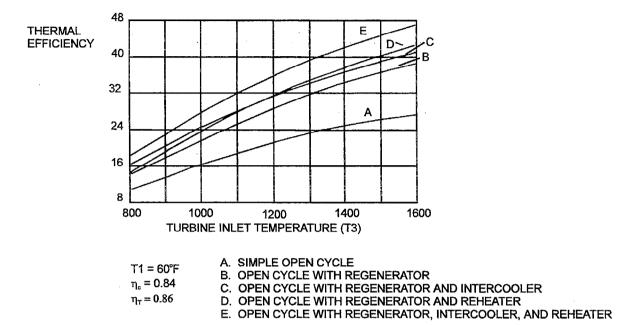


Figure 203.8 Effect of Regeneration, Intercooling and Reheat on Efficiency

When the turbine inlet temperature (T₃) is increased, the efficiency of the gas turbine increases, but the air rate decreases. This occurs because the horsepower increases. When the pressure ratio increases, the air rate decreases to a minimum value and then the air rate tends to increase with any additional increase in pressure ratio (Fig 204.1).¹⁴ Higher compressor inlet temperatures increase the required compressor work and decrease the net gas turbine work. Since the net output work is decreased, the air rate will increase.

Regeneration, intercooling, and reheating also affect the air rate. The regenerator tends to increase the air rate a small amount. Intercooling and reheating have a good effect on the air rate in that they reduce it, especially at high pressure ratios. With a reduced air rate the components of the gas turbine can be smaller. Higher compressor and turbine efficiencies will also create a reduced air rate.

204.2 WORK RATIO

The work ratio is defined as the net work (turbine output work minus work required for the compressor) divided by the turbine work.

THEORY & OPERATION

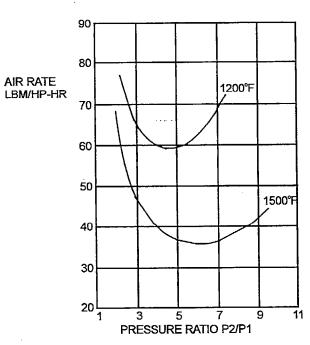


Figure 204.1 Air Rate vs. Pressure Ratio with Effect of Turbine Inlet Temperature (T3)

$$\alpha = w_{net}/w_{turb} = w_{turb}-w_{comp}/w_{turb}$$

Where:

 $\alpha = Work ratio$

 $w_{turb} = Turbine work$

 $W_{comp} = Compressor work$

 $w_{net} = Net work$

The work ratio can be used as a guide to determine the size of the gas turbine. It also helps indicate the sensitivity of a plant to decreases in the efficiencies of its component parts, such as the compressor and turbine. A gas turbine with a lower work ratio will not perform as well when there is any deterioration in the efficiencies of its components. The part load performance of a gas turbine will also decrease when the work ratio is lower. When a gas turbine power plant is run at part load, the efficiencies of component equipment are lower.

If a gas turbine has a work ratio of 40%, for example, it will provide 400 horsepower of useful work for every 1000 horsepower of turbine output. In this case 600 horsepower of every 1000 horsepower would have to be used to run the compressor and any other auxiliary equipment.

Compressor and turbine temperatures can have an effect on the work ratio. When the temperature of the air entering a compressor of a gas turbine is decreased, the work ratio increases. As stated earlier, decreasing the temperature of the inlet air into a compressor of a gas turbine generally decreases the work required for the compressor. Therefore, one would generally expect the work ratio to increase. Higher inlet temperatures into the turbine of a gas turbine increase the thermal efficiency of a gas turbine and also increase the work ratio (Fig. 204.2).¹⁵

The addition of a regenerator, intercooler and reheater tend to have a positive effect on gas turbine performance. As expected, the best performance and highest work ratio is attained when all three of the elements are used together.

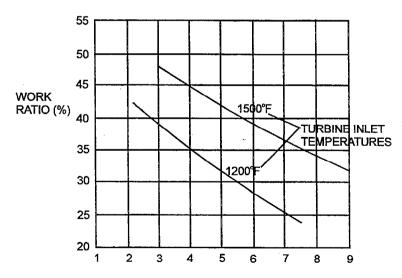


Figure 204.2 Work Ratio vs. Pressure Ratio

THEORY & OPERATION

204.3 WATER INJECTION TO INCREASE PERFORMANCE

Water injection is primarily known as a method of air pollution control for gas turbines, but it is also can be used to improve gas turbine performance. Water can be injected into a gas turbine in the air flow at the entrance of the compressor. The air stream is cooled by the latent heat of vaporization of the water. Energy is transferred from the air to the water, causing the air to cool and the water to evaporate. The cooled air is denser and less work is required to compress it, as in an intercooler. The mass flow of the air flowing through the gas turbine is increased so the power output is increased. Furthermore, the work ratio will increase, the air rate will decrease, and the range of optimum thermal efficiencies will be increased.

The water for injection must be pure. Any impurities in the water can lead to the formation of deposits on the turbine blades or cause corrosion. The injection of alcohol and other liquids can be used to create effects similar to water injection.

205 CLOSED GAS TURBINE CYCLE

Up to this point, only open cycle gas turbines have been discussed. In an open cycle air, which is the working medium, first flows through the compressor while being compressed, then through the combustor while being heated, and out the back end of the turbine to the atmosphere while being expanded. The air and combustion products only flow through the engine once. Although practically all gas turbines operate on a open cycle, they can also operate on a closed cycle.

Air Heater, Precooler and Regenerator In a closed gas turbine cycle, when the working medium exits from the turbine it is continuously returned back to the compressor. Instead of a combustor, a closed gas turbine is equipped with an air heater. Other equipment required for the closed cycle include the precooler and regenerator (Fig. 205.1). Fuel and air external to the closed cycle loop are fed to the air heater. As in a combustor, the air fuel mixture in the air heater is ignited, but the working medium passes through the air heater, absorbing heat from the combustion. The air heater is essentially a heat exchanger, where the working medium flows through tubes of high conductivity and the fire from the combustion is around the tubes. The unit can also be designed to operate with the fire in the tubes and working medium flowing around them.

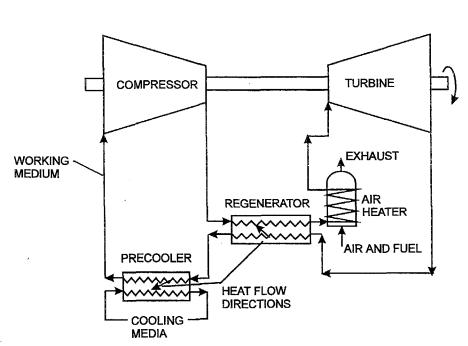


Figure 205.1 Closed Cycle Gas Turbine

After the heated working medium leaves the air heater it expands through a turbine, causing it to rotate. As in the open cycle, the temperature and pressure of the working medium decrease from the expansion through the turbine. The working medium then flows through the precooler (which is a heat exchanger) where heat is transferred from the working medium. Usually water is used as a coolant in the precooler. While the water flows through the tubes in the precooler, the working medium passes over the tubes, causing the working medium to be cooled. The working medium then enters the compressor and the work from the turbine is used to accomplish the compression. The working medium continues on to the air heater again. Some fossil fuel power plants in Europe operate using the principles of the closed cycle.

27

THEORY & OPERATION

205.1 ADVANTAGES AND DISADVANTAGES OF CLOSED CYCLE

The working medium does not have to be air, as in the open gas turbine cycle, since it does not have to support combustion. Denser, higher molecular weight gases with higher specific heats and higher pressures may be used. When a denser substance is used for the working medium, the size of the compressor and turbine can be smaller for the same power output.

Since control of the gas density in the closed system is possible, the output power can be varied without changing the pressure ratio or turbine inlet temperature. Therefore, a wide range of loads can be carried by the gas turbine with practically constant speed and efficiency, and the gas turbine's efficiency at part load is improved over the open cycle. Other advantages of the closed cycle are that the working medium is not subjected to combustion gases, so carbon deposits will not form. The compressor will also remain clean since it is not exposed to material in atmospheric air. This reduces the cleaning requirements of the components in the closed system. Furthermore, in addition to liquid and gaseous fuels, solid fuels can be used to power a closed cycle gas turbine.

There are a number of disadvantages with the closed cycle that make the open cycle a better design for most applications. The precooler in the closed cycle requires cooling water and a source of water is required. This makes the closed cycle impractical for aviation applications.

One of the major advantages with the open cycle gas turbine is its light weight and simplicity, but this is lost in the closed cycle. The closed cycle is much more complex and heavier because of the additional equipment required. The entire system must be gas tight so that the working medium will not leak from the system.

The air heater that is required for the closed cycle is large and heavy. The combustor in the open cycle gas turbine is more efficient than the air heater. The necessity of a air heater, precooler and gas tight system adds a lot to the cost of the closed cycle.

Gas Turbines

206 BASIC COMPONENTS OF GAS TURBINES

206.1 ORIENTATION OF GAS TURBINE COMPONENTS

In theory, multiple compressors, turbines and combustors can be used in various arrangements (Fig. 206.1). In the simple cycle gas turbine, air enters the compressor and is compressed, then enters the combustor and is ignited with fuel, and then the combustion products do work on the turbine. A second turbine can be added to extract more energy from the exhaust gases. In theory, another combustion chamber can be added to reheat the gases after the first turbine expansion. Additional compressors can be added to further compress the air, increasing the overall pressure ratio and efficiency.

In actual practice, it is common for gas turbines to have two compressors and two turbines with one combustor. The first compressor that the air enters is called the low pressure compressor. If there is a second compressor, it is called the high pressure compressor, since it raises the pressure of the air higher than the low pressure compressor. The low pressure compressor has a larger diameter than the high pressure compressor, and the compressor blades on the low pressure compressor are larger than those of the high pressure compressor. This type of design is called a "split compressor" or "twin spool" engine.

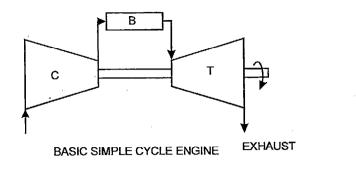
If there are two turbines after the combustor, the first turbine after the combustor is called the high pressure turbine. The second turbine that the exhaust gases flow through is called the low pressure turbine. When the air enters the first turbine it is near its highest pressure, and by the time it exits the high pressure turbine and enters the low pressure turbine the pressure of the gases has decreased substantially. The diameter and blade size of the high and low pressure turbines is analogous to the size in the high and low pressure compressor. The low pressure turbine has a larger diameter and larger blades.

The low pressure compressor is driven by the low pressure turbine and the high pressure compressor is driven by the high pressure turbine. A coaxial shaft is often used in gas turbines with high and low pressure compressors and turbines. The shaft between the low pressure compressor and low pressure turbine rotates within the shaft for the high pressure compressor and the high pressure turbine.

Low & High Pressure Compressors

Split Compressor, Twin Spool

Low & High Pressure Turbines



C = COMPRESSOR

B = COMBUSTOR

T = TURBINE

LPC = LOW PRESSURE COMPRESSOR

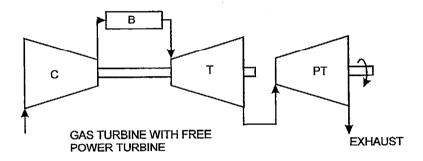
HPC = HIGH PRESSURE COMPRESSOR

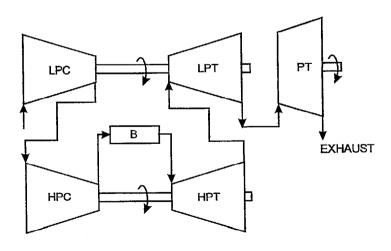
LPT = LOW PRESSURE TURBINE

HPT = HIGH PRESSURE

TURBINE

PT = POWER TURBINE





DUAL COMPRESSOR ENGINE

Figure 206.1 Various Open Cycle Gas Turbine Arrangements

Gas Turbines

The two shafts rotate totally independent of each other (Fig. 206.5 and Section 208, Fig. 208.4 and 208.5). The high pressure compressor and turbine rotate at a faster velocity than the low pressure compressor and turbine.

The advantage of having a split compressor system is that the engine will have more operating flexibility without stalling. This is especially important for aircraft. Since the low pressure compressor is allowed to operate at its best speed while the high pressure compressor is speed-regulated by fuel control, the chances of stalling are reduced. On stationary gas turbines the high pressure compressor and turbine can be run at the most optimum speed while the low pressure compressor and turbine are varied to meet load requirements. Compressor stall occurs when the velocity of the air slows to a point where the angle of attack of the air to the compressor blades becomes poor enough to reach a stall value. Furthermore, the pressure ratio is increased substantially in a dual compressor engine. Although not as common, gas turbines with three compressors and three turbines with a triaxial shaft have been designed and built (see Section 208, Fig. 208.5).

The power turbine is added to aero-derivative gas turbines (those originally from aircraft) to convert the thrust force that jet engines produce into shaft horsepower. The power turbine rotates independently from the high and low pressure turbines. In a gas turbine originally designed to operate as a stationary engine creating shaft horsepower, retrofitting of a power turbine may not be necessary. The output shaft from the turbine may be connected to a generator without a separate power turbine. Gas turbines designed to operate as stationary engines may be heavier and more bulky than aero-derivative gas turbines and they may be called "heavy duty" or "industrial" engines or manufacturers may have specific names for their stationary engines. Some heavy duty gas turbines are very large and dwarf the size of aero-derivative engines.

206.2 COMPRESSORS

Compressors increase the pressure of air before it enters the combustor for combustion. The compressor gets more air in the engine, and in general the more air that is put in the engine the more power will be produced. The energy released by the combustor is proportional to the mass of the air that enters the

Power Turbine

THEORY & OPERATION

engine, so the compressor is an important part of the engine. The main kinds of compressors that have been used with gas turbines include positive displacement, centrifugal flow, and axial flow compressors.

206.2.1 Positive Displacement Compressors

Positive displacement compressors compress a fixed amount of gas for every cycle or revolution of the device. Reciprocating and rotary action compressors are two basic types of positive displacement compressors. Reciprocating action compressors typically use pistons, plungers or diaphragms to compress air or a gas. Rotary action compressors use rotating screws, lobes or vanes to compress air or a gas. Some early gas turbines were built with positive displacement compressors, but they are not used to run modern gas turbines. Applications of positive displacement compressors for gas turbines are limited because of their high noise level, limited speed, limited pressure ratio, and high weight.

206.2.2 Centrifugal Compressors

Impeller

Diffuser

Centrifugal compressors use centrifugal force to compress air. A rotating impeller is used to impart energy to air or a gas to compress it. After flowing through fixed guide vanes at the compressor entrance, air enters the center of the compressor impeller hub and moves radially outward. At first the air flows axially, parallel to the shaft on which the impeller rotates, then it is channeled by the impeller with a 90° change in direction, and discharged into the diffuser (Fig. 206.2). The mechanical energy of the rotating impeller is transferred to the air by increasing its velocity. The air flows radially outward along the vanes of the impeller and the air's velocity and pressure increase as it moves outward. Some energy from the impeller increases the air's temperature from friction between the air and the blades and due to the work done on the air. When the air leaves the impeller it enters divergent nozzle vanes in the diffuser that convert the kinetic energy of the air into pressure energy (Fig. 206.3). It is common to design the impeller so that half the pressure rise occurs in the impeller and half occurs in the diffuser.

Gas Turbines

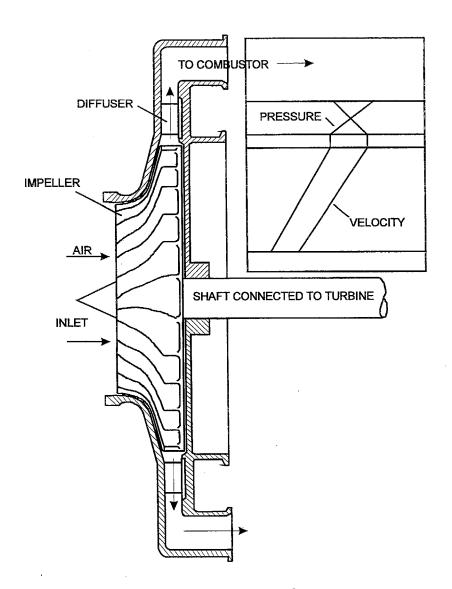
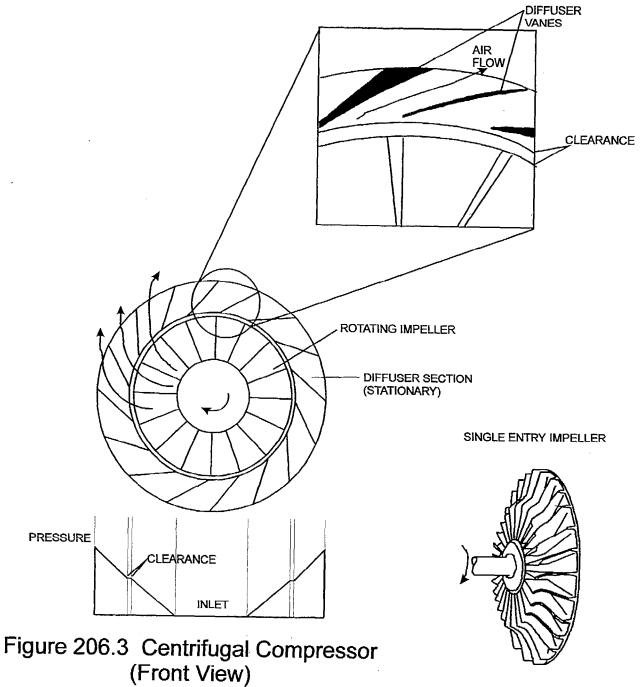
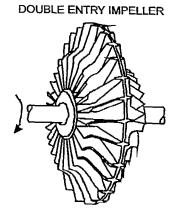


Figure 206.2 Centrifugal Compressor





TWO STAGE SINGLE ENTRY IMPELLER

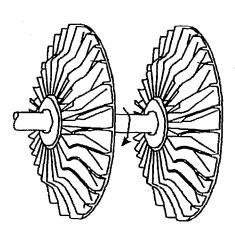


Figure 206.4 Centrifugal Compressor Impellers

Gas Turbines

Figure 206.4 illustrates the main types of centrifugal impeller designs used for gas turbines, including the single stage impeller, two stage impeller and the dual entry impeller. The two stage impeller compressor provides a two stage compression and the dual entry design compresses air on each side of the impeller.

Pressure ratios for centrifugal compressors are generally between 1.5:1.0 to 5:1, but some experimental single stage units have attained a pressure ratio of over 12:1. Centrifugal compressors can reach an efficiency of 80% with a pressure ratio between 4 and 5 to 1.

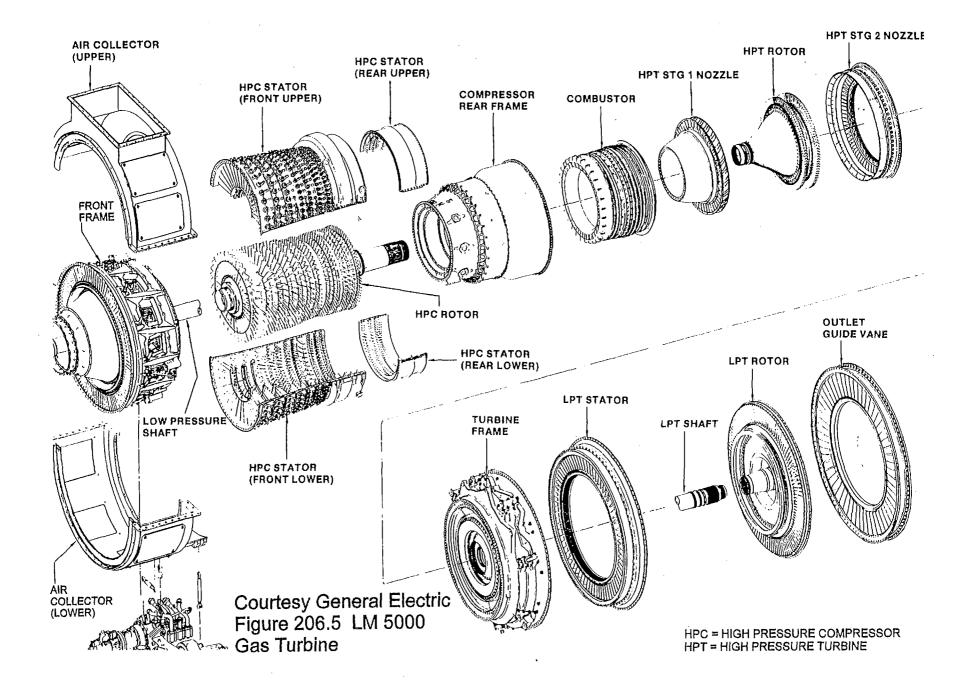
206.2.3 Axial Compressors

The axial compressor is used in most modern gas turbines. It has a cylindrical hub with "rings" or stages of rotor blades. In between each set of rotor blades are the stator blades. The stator blades do not rotate and they are a part of the case that surrounds the compressor rotor (Fig. 206.5). The case is often in two halves, so that the compressor can be opened and inspected or repaired. The number of stages is usually determined by the number of rows of blades on the rotating rotor. There is usually one more set of stator vanes than rotor blades since the stators are at the front and rear end of the compressor. At the ends of the larger sized stator blades toward the center of the rotor are shrouds that connect the ends of the stator blades together. The shrouds help prevent air from being lost in the inner part of the compressor or being lost between stages and it helps reduce vibrations. Small stators toward the rear of the compressor often do not have shrouds. Each stage of stator blades changes the direction of the air flow (angle of attack) as it leaves the rotor, so it will enter the next rotor stage at the correct angle.

From the inlet of the compressor to the outlet of the compressor each stage of stator blades and rotor blades gets smaller. From the front to the back of the compressor the annular area between the stator casing and the rotor case gets smaller. This can be done by tapering down the stator casing from front to back, or increasing the inner diameter of the rotor from front to back, or a combination of both. Note how the central part of the rotor is "cone shaped" and the inner diameter of the rotor forms a shell that is supported on the central cone

Shrouds

Compressor Taper



Gas Turbines

(Fig.206.6). The annular area decreases toward the end of the compressor in order to maintain a near constant axial velocity as the density of the air increases through the compressor.¹⁷

Air is drawn into the compressor and the rotating rotor increases the air's velocity. Then the air is diffused to a lower velocity with a corresponding increase in pressure by the next stator passage (stage). The increase in velocity imparted to the air increases the kinetic energy of the air. When the velocity of the air is decreased, the kinetic energy of the air is converted to pressure energy. The temperature of the air also rises during the compression. Then the process occurs again in each successive rotor and stator stage. Figure 206.6 illustrates how pressure and velocity vary through the length of the compressor.

The pressure increase from a single stage may result in a pressure ratio that varies between 1.1:1.0 to 1.4:1.0, and the overall pressure ratio for the compressor may be around 18:1 or more. Some of today's compressors have pressure ratios as high as 30:1.¹⁸ The pressure is increased only a small amount each time to avoid losses from air breakaway at the blades and blade stall.

If, for example, the pressure ratio for a compressor was 10:1, the outlet pressure of the air exiting the compressor would be approximately 147 psi. The inlet pressure to the compressor is atmospheric pressure (14.7 psi). Furthermore:

$$P_{\text{outlet}}$$
 = Outlet pressure of compressor P_{inlet} = Inlet pressure of compressor $P_{\text{outlet}}/P_{\text{inlet}}$ = 10 P_{outlet} = 10(14.7) = 147 psi.

Air follows a helical path through the compressor. The last stage of stator vanes usually acts as an air straightener before it enters the combustor. Figure 206.7 shows a view of an axial compressor, looking down the compressor blades. The diagram shows how the pressure increases in each stage. Note that each of the blades has an airfoil (airplane wing) shape.

How Pressure is Increased

Pressure Ratios

THEORY & OPERATION

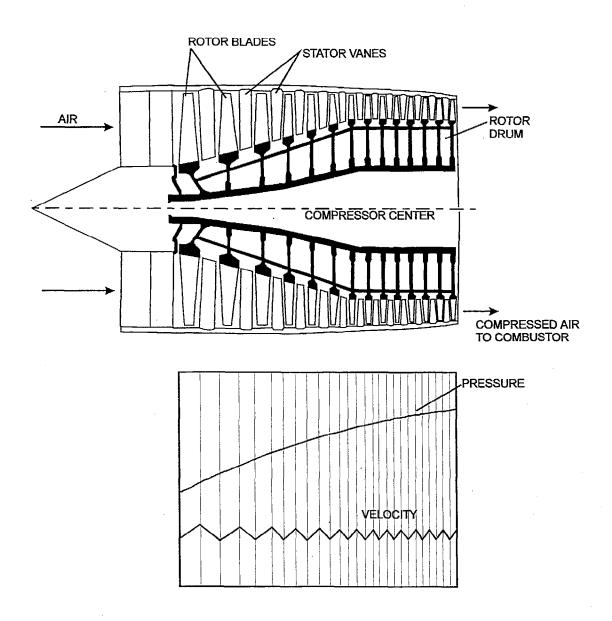


Figure 206.6 Velocity and Pressure in Axial Compressor

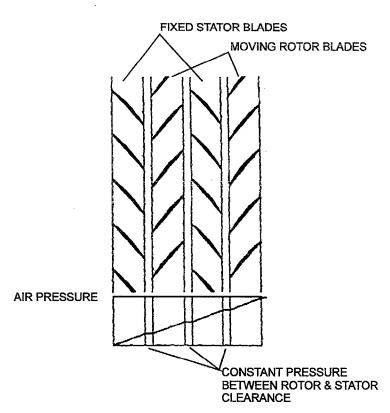


Figure 206.7 Edge View of Axial Compressor and Stator Blades and General Pressure Distribution

Variable Stator Vanes

Most modern compressors, especially aero-derivative gas turbines, are equipped with adjustable stator vanes. The angle of the stators can be changed to improve the performance of the engine. The angle of the stator vanes is automatically regulated by the fuel control unit which controls the amount of fuel for the engine. With variable stator vanes the direction of the interstage air flow can be controlled. Therefore, the correct angle of attack (the angle which the air flows over the rotor) can be assured for each compressor stage. The angle of attack is an important parameter for proper compressor operation. Having variable stator vanes helps prevent compressor operation in the instability region (poor air flow characteristics in the compressor) during low load and low speed operation. Part of the variable stator system on a compressor can be seen from the linkages on the outside of the stator case. The linkages connect to the stators.

June 1996

THEORY & OPERATION

The higher the pressure ratio in a compressor, the more difficult it becomes to operate the gas turbine efficiently over the full speed range.¹⁹ At high speeds, the inlet area of the air becomes too large for the exit area. The velocity of the air at the inlet becomes too slow relative to the speed of the rotors, and the angle of attack of the air on the blades becomes poor. The air flow then begins to separate and break down and the engine could stall. Variable stator vanes help prevent this from occurring. Interstage bleeds in the compressor can also prevent this form of compressor stall, but this would be a waste of energy. Bleeds are used in emergencies to protect the compressor.

Fixed Stator Vanes

It is common for gas turbines to have both variable and fixed stator vanes. Three basic types of fixed stator vane orientation designs include the symmetrical stage, the unsymmetrical stage, and the vortex stage (Fig. 206.8).

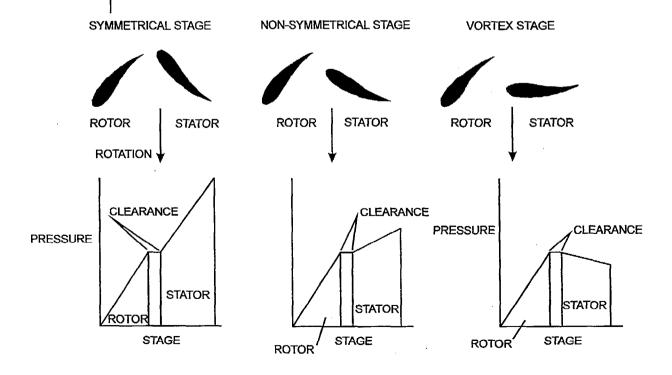


Figure 206.8 Fixed Stator, Axial Compressor Stages

Gas Turbines

The relative pressure across the rotor and stator is also shown. The clearance noted in the figure is the distance between the rotor and stator. The pressure between the rotor and stator is constant.

The symmetrical stage is a stage where the pressure rise in the rotor and stator is equivalent at any given distance from the center of the compressor's rotation. In the non-symmetrical stage the ratio of the pressure rise through the rotor and stator blades is constant along the blade length, but the pressure rise in the stator and rotor at a given radius is not constant. A vortex stage is where the angular momentum acting on a given particle of fluid (air) in the radial direction is constant. Although this type of stage actually has a pressure decrease across the stator, in theory losses at the blade tips are reduced, and efficiencies are high. A fixed stator compressor can use a combination of these stator orientations in a single compressor.

Axial/Centrifugal Compressor Comparison

Centrifugal compressors are stronger than axial compressors. The impellers of centrifugal compressors are stronger than the thin blades of the axial compressor. The small stator and rotor blades at the back of the compressor are especially fragile and susceptible to damage from foreign objects. Centrifugal compressors are also simpler and less expensive to manufacture. An axial compressor may have over 1000 blades and stator vanes; furthermore, close fits between its parts are required for efficient operation. Axial compressors are more sensitive to changes in air flow rate and rotational speed and have a narrower range of operating conditions. Changes in air flow rate and rotational speed can lead to a rapid drop in efficiency. This also has a negative effect on the part load performance of the compressor and gas turbine.

On the other hand, in practically all applications for gas turbines, axial compressors are used because of their advantages. Axial compressors are more efficient than centrifugal compressors. It is cheaper to manufacture a centrifugal compressor, but the cost savings is lost from the decreased efficiency. Centrifugal compressors have a larger diameter, increasing space requirements and frontal area. The increased frontal area is a large disadvantage for aircraft applications, since this contributes to more drag. Given a centrifugal

THEORY & OPERATION

compressor and an axial compressor with the same frontal area, the axial compressor will consume more air; therefore, a higher pressure ratio and more output power can be produced.

Centrifugal compressors are not as adaptable to multi-staging. Most of the centrifugal gas turbines ever made used a maximum of two stages. A centrifugal compressor is the best option to use for small engines when the application requires strength and simplicity, but a lower pressure ratio and other disadvantages can be tolerated. Centrifugal compressors are often used for the small engines in auxiliary power units.

206.3 COMBUSTORS

Aircraft Combustors

Silo Combustors

Canted Can

Silo Combustors

The combustor is the combustion chamber for the gas turbine. The main types of combustors for aircraft engines and most aero-derivative engines are the can, the annular, and the can-annular (or cannular) combustor (Fig. 206.5, Fig. 206.9). Silo combustors are another type that may be used on aero-derivative gas turbines but not on aircraft (Fig. 206.10). The can combustor has separate "cans" around the engine which behave as separate combustion chambers. Each can has its own fuel nozzle and may have its own igniter, but some can designs have cross-over tubes between cans to spread the flame instead of having an igniter in each can. A variation of the can type is the canted can combustor which has combustor cans mounted so that they are not parallel to the centerline of the gas turbine. In the annular combustor, a single combustor with an annular shape is used. The annular combustor has fuel nozzles spaced evenly around the circumference. The can-annular combustor is a combination of the can and annular combustor. It has separate cans within an annular chamber.

Another type of combustor, known as the silo type, is mounted externally to the gas turbine and is usually used on stationary engines (Fig. 206.10). This type of combustor may also be called the "single can", "sore thumb", or "green thumb" combustor by various manufacturers. A single can design is usually a smaller sized external combustion chamber, and silo combustors are usually referred to as the larger sized combustors with a length that is over two times the diameter of the gas turbine. More than one external combustor can be used in the silo design.

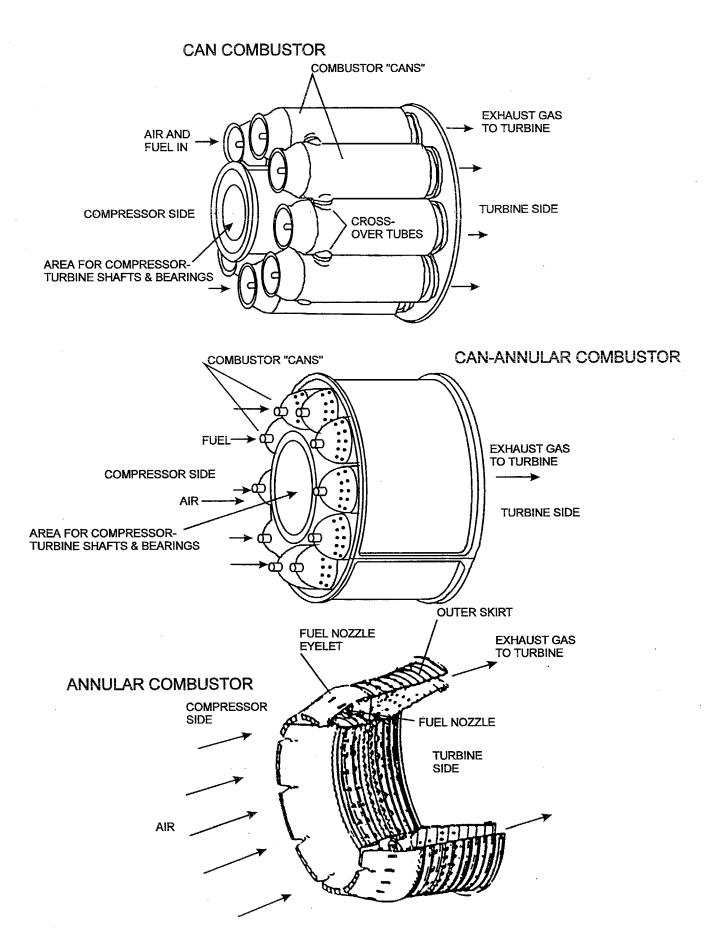


Figure 206.9 Gas Turbine Combustors

THEORY & OPERATION

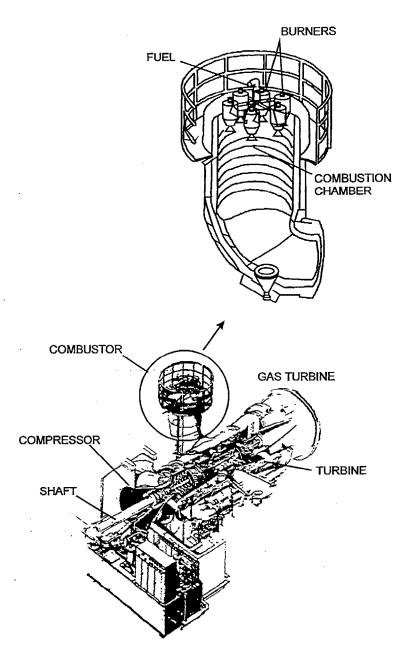


Figure 206.10 Silo Combustor

Gas Turbines

Silo combustors look like grain silos or cylinders and they are generally mounted perpendicular to the gas turbine. Some retrofitting is required when they are installed on aero-derivative engines. Silo combustors are generally not used as much as the three previously mentioned combustors. The inside of the silo combustor is fitted with a ceramic lining to protect the metal of the combustor from heat.

The annular type is 3/4 of the length of the can type; therefore the engine can be smaller and lighter. Because of the weight savings, annular combustors are often used on aircraft engines.

Can type combustors are easier to manufacture, service and test. Individual burners can be easily inspected, removed and replaced, but in the annular design the entire combustor must be removed for servicing. In the annular type all the front or rear sections (i.e. compressor or turbine rear frame, guide vanes, stators, rotors, front frame) must be removed before gaining access to the combustor. During testing of can combustors, only one can needs to be tested. The annular type is much more likely to have structural problems because of its large diameter, relatively thin walls, and exposure to high temperatures. The canannular has more structural stability than the annular type, but it has a larger surface area that must be cooled.

The combustor is the most efficient part of an open cycle gas turbine since it is more efficient than the compressor and turbine. Combustion efficiencies can approach 100% at sea level, but for aircraft at cruising altitudes the efficiency can drop to 98%.^{22.1}

Combustors have an outer cylindrically shaped shell and an internal liner. In the center of the combustor at the front end of the liner are the fuel nozzles. The holes toward the front part of the liner allow compressor air to flow into the combustion chamber. Air and an atomized spray of fuel mix when they enter the combustor and are ignited by an igniter plug, which is similar to a spark plug. The front part of the liner is sometimes called the primary zone. Air also enters the combustion chamber through the sides of the liner in the primary zone to help mix air and fuel for combustion. Air flowing through the holes in the primary zone tends to recirculate upstream opposite the flow of the fuel. This flow pattern helps increase turbulence and increases mixing of the fuel and air. Air enters the combustor at a velocity of about 500 ft/sec, which is too fast for combustion. Kerosene, which is essentially the same as the jet fuel, burns at

Combustor Comparisons

Combustor Liner

Igniter Plug

THEORY & OPERATION

only a few feet per second, so at these high velocities, the flame would be blown out of the engine. The design of the combustor helps diffuse the entering air to a lower velocity and the recirculating motion in the combustor provides a stable low velocity zone where the flame can burn (Fig. 206.11).

Flame Temperature

Besides providing combustion, air that flows through the first row of holes in the liner helps cool and clean the liner and fuel nozzle. Only about 25% of the air from the compressor takes part in the combustion process. The flame in the combustor burns like a blow torch and without proper design to provide ample cooling air, the combustor flame would burn through the liner. Air flows around the liner and acts as a blanket, preventing the liner from getting too hot. Flame temperatures in a combustor can reach 2000° C (3600° F), which is too high for exposure to the combustor structural materials. Air insulates the combustor from the peak flame temperatures. Air also flows through holes in the liner downstream of the primary zone in a zone called the secondary or dilution zone. Besides cooling the liner, this air helps cool the combustion products before they enter the turbine. Air flowing through the holes toward the rear of the liner dilutes and therefore cools the combustion gases. Air will dilute and cool

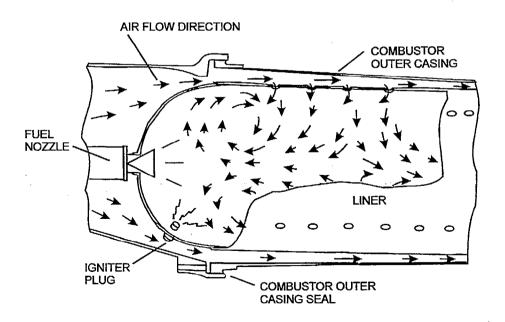


Figure 206.11 Combustor Liner and Air Flow

Gas Turbines

combustion gases to temperatures between 1800 to 2500° F by the time they reach the turbine. This cooling is required to prevent the heat from damaging the turbine blades.

With higher temperatures in the combustor, higher efficiencies and more output work may be attained, but with higher pressures and thermal stresses the life of the engine will be shortened due to the deterioration of the materials in the engine. Not only must the combustion gases not be too hot, the air that cools the combustor (also called secondary air) must mix uniformly with the hot products of combustion so that the turbine blades will be exposed to a uniform temperature.

Combustors differ from the combustion chambers for other engines (such as internal combustion engines) in that there is a large continuous velocity of air (150 to over 400 ft/sec) in a gas turbine combustor. There is also a large air fuel ratio for combustors, because only about 25% of the air that enters the gas turbine is used for combustion; the rest is primarily used to cool the combustor and reduce the temperature of exhaust gases to the allowable turbine inlet temperature.

206.3.1 Combustor Performance

For a combustor to perform well, it must have a high combustion efficiency, it must have a low pressure loss, and it must have a stable flame. A high combustion efficiency is necessary for a high overall thermal efficiency. When the combustion efficiency is low, unburned fuel could be exiting the combustor and burning in the turbine and exhaust. Fuel burning in the turbine is detrimental to the turbine blade life. Flame stability means a steady constant flame. A flame that has poor stability will pulsate and could blow out. Pressure and the velocity of the gases in the combustor have a large effect on the range of a stable flame. The lower the pressure is, the narrower the range of stable flame operation. If the pressure is continually lowered the flame will become unstable and will not be able to burn. Higher exhaust gas velocities will also decrease the stable flame operating range. If the velocity is increased to its critical velocity, the flame will blow out.

Flame Stability

THEORY & OPERATION

Carbon Deposits

In addition, requirements for good combustion include: low amounts of deposits formed in the combustor, turbine and regenerator (if there is one); the equipment must be serviceable and have a reasonable life; and (especially for aircraft) the frontal area and weight must be minimized.

The amount of carbon deposits formed can vary with different burners, but deposits generally get worse with higher temperatures and pressures. If temperature and pressure in a combustor are continually increased, carbon deposits will eventually begin to burn off. Increasing the fuel/air ratio also tends to increase the formation of carbon deposits, and changes in the fuel/air ratio can change the locations where they form. The type of fuel used can also have a significant effect on the formation of carbon deposits.

Creating a uniform temperature in the exhaust products entering the turbine is done by having good mixing between the dilution air and the exhaust products. Decreasing the fuel/air ratio and the velocity in the combustor tends to make the exit temperatures more uniform, since less heat is released and there is less time for mixing.

206.4 TURBINE

The turbine does the inverse of the compressor; the turbine extracts kinetic energy from the hot, high-velocity gases leaving the combustor. As stated earlier, the compressor adds kinetic energy to entering air by increasing its velocity, and the velocity of the air is then decreased, creating a corresponding increase in pressure. The kinetic energy extracted by the turbine is converted to shaft horsepower by the rotation of the turbine. Approximately 75% of the turbine horsepower is used to drive the compressor. In stationary gas turbine operations, over 90% of the energy of the combustion gases will be extracted by the turbine.

206.4.1 Types of Turbines

There are two basic types of turbines, which are analogous to the centrifugal and axial types of compressors. These two turbines include the radial-inflow turbine and the axial-flow turbine. The radial-inflow turbine is essentially a centrifugal compressor with a reversed flow. Less than 20% of gas turbines use the radial-

Gas Turbines

inflow type of turbine and they are usually used for smaller loads and for smaller operating ranges than axial turbines. Radial turbines are shorter than axial turbines, which can be an advantage depending on the application. As with centrifugal compressors, radial-inflow turbines are stronger than axial turbines and are easier and cheaper to manufacture.

There are two types of radial-inflow turbines, the cantilever type and the mixed-flow type. The cantilever type is actually similar to the axial turbine, but the flow of combustion gases is directed radially inward, unlike the axial turbine. The mixed-flow turbine is almost identical to a centrifugal compressor, but it operates in an opposite manner. The combustion gases enter the turbine radially and exit axially, turning the turbine.

Radial-Inflow Turbines

206.4.2 Axial Turbines

The types of axial turbines (almost all gas turbines use the axial type) include the impulse turbine, the reaction turbine and a combination of the two (a reaction-impulse turbine). Most aero-derivative gas turbines use the reaction-impulse type. In the impulse type turbine, energy is transferred from hot combustion gases to the turbine by the change in direction the gases make when they pass through the turbine blades (Fig. 206.12). In an impulse turbine the gases enter and exit the turbine at essentially the same speed and pressure, but in a different direction. In a reaction turbine the speed and pressure of the combustion gases is changed after they flow through the turbine. The cross-sectional area of the passages between turbine blades in the reaction turbine decreases as the gases flows through it (Fig. 206.12). As the gases are forced into a smaller space, the velocity of the gases increases with a corresponding pressure decrease. The turbine absorbs the energy that was needed to change the velocity of the gases.

In a reaction-impulse turbine stage the turbine blade is a blend of the reaction and impulse type. The turbine blade is formed to perform as an impulse turbine toward the root of the blade and as a reaction turbine toward the tip of the blade. This type of design is used to distribute power along the blade. Uneven power distribution along the blade will result in different exhaust gas velocities and pressures when the gases exit the blade.²⁵

Impulse Turbine

Reaction Turbine

Reaction - Impulse Turbine

THEORY & OPERATION

Nozzle Vanes

As with axial compressors, axial turbines are equipped with a stator case with stationary vanes. The stator vanes in the turbine, especially the first row closest to the combustor, are also called nozzle guide vanes by some manufacturers (Fig. 206.5). The vanes are designed to increase the velocity of the exhaust gases from the combustor with a corresponding decrease in pressure before they hit the turbine blades. The nozzle vanes also direct gases at the appropriate angle to the turbine blades. The nozzle vanes are analogous to a water nozzle and the turbine blades are analogous to buckets. Ideally, turbines would be equipped with variable stator vanes, but the stator vanes on the turbine are fixed.

The theory, design, evaluation and operating characteristics of the turbines in gas turbines are similar to those of steam turbines. Gas turbines differ in that the turbine for gas turbines is exposed to higher temperatures, the materials for

IMPULSE TURBINE

REACTION TURBINE

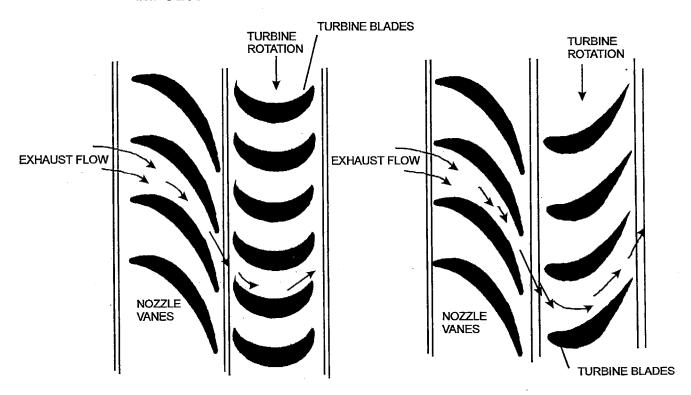


Figure 206.12 Impulse and Reaction Turbine Blades

Gas Turbines

construction of the turbine are different and they have a higher ratio of blade length to wheel diameter. Because of the higher temperatures, the turbine blades are made with more advanced heat resistant materials. Blades with a higher ratio of length to wheel diameter are used to accommodate large flow rates.

The turbine must be light (especially for aircraft applications), it must be able to withstand high temperatures for long periods of time, it must be resistant to vibration and corrosion, it must be reliable and easily serviceable, and be resistant to mechanical and thermal shock. The higher the temperatures the turbine is exposed to, the shorter the turbine's operating life.

Materials and Construction

Research is still being conducted on turbine blade materials that will last longer at higher temperatures. The severe conditions that the turbine operates under eventually requires repair and replacement of highly stressed parts. Most materials can only handle about half the maximum temperatures (about 4000° F) attainable with hydrocarbon fuels. Special metal alloys, powdered metals, ceramic materials, and combination ceramic metal materials may be used for turbine blades. The special metal alloys are usually made with a nickel or cobalt base. Some turbine blades and nozzle vanes are designed with intricate cooling passageways for cooling air. Air bled from the compressor is often used as a coolant and experiments with liquid coolant have been conducted.

Coatings may be used to protect turbine parts from corrosion. Research is being conducted to use fuel additives to prevent corrosive elements such as sulfur, salt, and vanadium from attacking hot turbine parts.

The two main parts that make up a turbine are the turbine blades and the disk. The disk is often made mostly of alloyed steel, chromium, nickel and cobalt. After it has been forged, it is carefully tested with x-rays, magnetism, and other methods to make sure it is structurally sound. Blades are attached to the disk with a "fir tree" design fit. The blades are prevented from sliding out of the disk by rivets, locking tabs, or other devices. The turbine must also be carefully balanced.

THEORY & OPERATION

Shrouded Blades

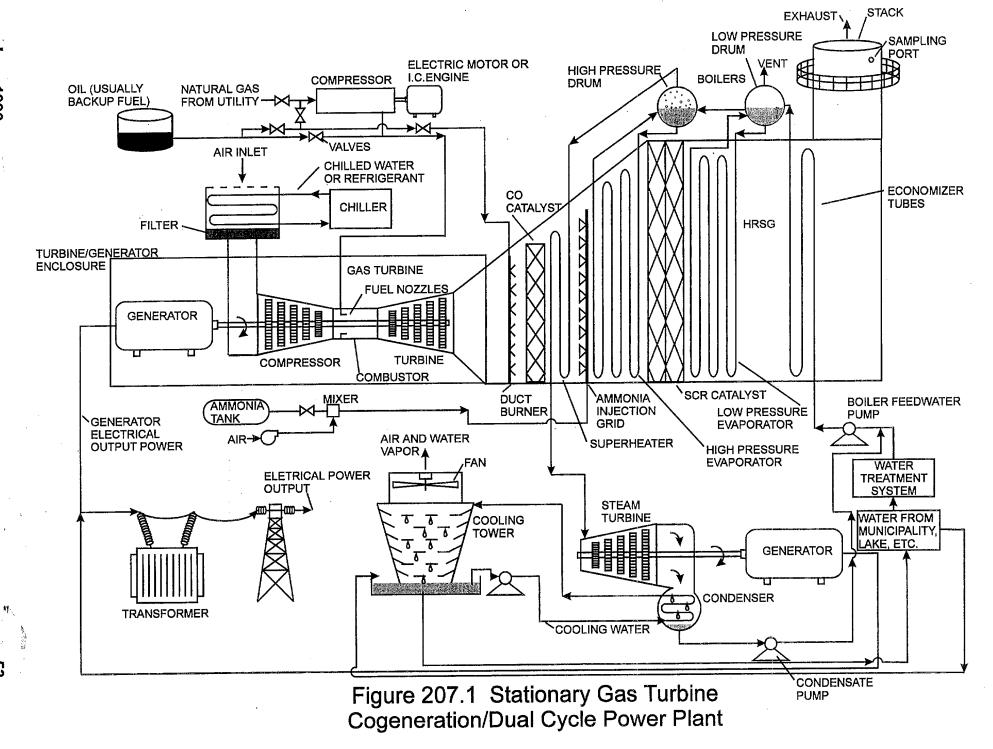
Turbine blades may be shrouded or open at the tips. A shroud helps prevent blade tip losses and excessive vibrations. Shrouded blades also tend to resist distortion from high loads. The added rigidity of the shroud prevents the blades from twisting. On the other hand, a turbine with shrouding must be run at cooler temperatures or at reduced speeds. The turbine is designed to distribute the load evenly between all the turbine stages, so each successive stage has larger blades with a larger area.

207 STATIONARY GAS TURBINE COGENERATION/ COMBINED CYCLE POWER PLANTS

Power plants use a variety of methods to produce electrical energy for homes, cities, government, and industry. The electrical energy from power plants comes from generators, but energy is required to turn the shafts of the generators to produce electricity. The mechanical energy that runs the generators can come from relatively clean sources such as water flowing downhill in a river or from a lake (hydroelectric power). Some dams are equipped with turbines that are run by moving water to turn the generators. A power plant often uses steam to turn turbines to make electricity. The heat to create the steam can come from heat underground (geothermal power), or fission in a nuclear reactor (nuclear power), but the heat usually comes from the combustion of a fossil fuel which pollutes the air. The combustion of a fuel in a power plant can be used to create steam in a boiler. The fuel can also be used to run an engine such as a reciprocating internal combustion engine or gas turbine to directly turn generators for electricity. The main use for stationary gas turbines is to produce electrical power in a power plant.

Conditioning of Entering Air

Before air enters the gas turbine it is filtered, to prevent material from getting into the compressor and collecting on the compressor blades or other equipment (Fig. 207.1). Modern filtering systems are equipped with self cleaning mechanisms. Pulses of compressed air may be used to provide cleaning of the filters. Many modern power plants with gas turbines cool the entering air with a chiller or air conditioner coil to maximize the efficiency. The cooling water used may come from chilled water from the cooling tower.



THEORY & OPERATION

The air enters the compressor of the gas turbine and is compressed. Only about a quarter of the air is used for combustion and the rest is used to provide cooling to the gas turbine. Cooling air must be continually delivered to the liner in the combustor to prevent damage from excessive temperatures and to cool gases to the turbine inlet temperature.

Compressed air enters the combustor, fuel is added and the air fuel mixture is ignited. Hot gases then expand through the turbine of the engine, forcing the turbine to turn rapidly. The energy transferred to the turbine is mostly used to turn the compressor. The shafts of the turbine and compressor are directly connected. Some designs may have gearing between the generator and gas turbine to attain the desired revolutions per minute (rpm). The net output energy of the turbine turns the generator to convert the mechanical energy of the gas turbine into electricity. Cooling is also required for the generator. Air is drawn into the generator enclosure for cooling. Some generators are water cooled and oil is used to provide lubrication and cooling. The generator may be mounted on the turbine side of the gas turbine or on the compressor side, depending on the type of gas turbine.

Type of Fuel

Most stationary gas turbines use natural gas as a fuel. The natural gas is delivered to the plant by a pipeline. Compressors are used to increase the pressure of the natural gas to the pressure that is required for the fuel injectors in the combustor. An electric motor or engine may be used to run the natural gas compressor. Oil may also be used to run the gas turbine, but it is usually a backup fuel in case natural gas is temporarily unavailable.

HRSG

Some gas turbines also have equipment to extract more energy from the hot gases leaving the turbine (Fig. 207.1). Feed water pumps run water through heat exchangers in the exhaust portion of the gas turbine called the heat recovery steam generator (HRSG) or waste heat boiler. The heat exchangers are generally large bundles of tubes made of highly conductive materials such as steel. Hot gases exchange heat energy with the water through the boiler tubes before the exhaust exits the stack. A power plant is a cogeneration plant when it produces power and also makes steam that is sent elsewhere to run other equipment. This steam could be used to heat water, heat air for space heating, turn a turbine for mechanical energy or to operate other industrial processes.

THEORY & OPERATION

Gas Turbines

The heat recovery sections in the heat recovery steam generator may include the economizer, low pressure, intermediate pressure, and the high pressure section. The economizer is generally the last heat exchanger in the system before flue gases are released to the stack. As its name implies, its function is to capture as much of the last amounts of heat energy available in the stack gas to save money. Feedwater pumps pump the water through the economizer and then into the low pressure drum or boiler. After being heated by the economizer, the water circulates through the low pressure boiler tubes and comes back to the low pressure boiler, increasing the temperature of the water. The low pressure section is also called the deaerator, because dissolved corrosive gases are usually removed from the water in this section. Oxygen is the primary gas that is removed. Steam is sent from the low pressure boiler to the intermediate boiler. Heated water from the economizer is also pumped to the intermediate section. As with the low pressure boiler, the intermediate boiler is a heat exchanger that absorbs heat from the flue gas. The intermediate steam produced from the intermediate boiler is at a higher pressure and temperature than the steam from the low pressure boiler. For simplicity, only one feedwater pump is shown and the intermediate boiler section has been left out of Figure 207.1.

Steam from the intermediate boiler and feedwater is sent to the high pressure boiler. Water flows from the high pressure drum into the tubes of the high pressure boiler, returning to the high pressure drum and creating high pressure steam. Steam from the high pressure drum or boiler then goes to the superheater. The superheater is located toward the hottest section of the HRSG. Only water that is in its gaseous state is sent to the superheater. The superheater increases the pressure and temperature of the steam to its highest value in the system. Superheated steam from the superheater is sent to a steam turbine to produce more energy. Intermediate steam and low pressure steam may be drawn off the intermediate and low pressure boilers to supplement the steam turbine, to run other processes or for steam injection into the gas turbine.

At the front side of the heat recovery steam generator near the exit of the gas turbine, the temperature of the gases is generally around 1,000°F. By the time the flue gases exit the stack of the HRSG, the temperature is generally in the 200 to 300°F range.

A duct burner can be installed at the front side of the HRSG. The purpose of the duct burner is to add additional heat to the flue gases exiting the turbine utilizing the available oxygen. Some duct burner designs can also allow the steam plant

Economizer

Deaerator

Duct Burner

June 1996 200 - 55

THEORY & OPERATION

to operate when the gas turbine is not in operation, but this operation (fresh air firing) is not common practice since is not very efficient. Fresh air may be added for the burner by a fan upstream of the duct burner. Additional fuel (usually natural gas) is added to the burner.

Pollution Control /SCR Equipment

Equipment for air pollution control in the heat recovery steam generator includes the carbon monoxide catalyst, the ammonia injection grid and the selective catalytic reduction catalyst. The carbon monoxide catalyst is used to help remove carbon monoxide by oxidizing it to carbon dioxide. Ammonia is injected in the HRSG for NOx control. Ammonia and the selective catalytic reduction catalyst work to change NOx compounds into nitrogen.

Steam Turbine/ Combined Cycle

Superheated steam from the HRSG is injected into a steam turbine. As the steam expands through the turbine its temperature and pressure decrease and energy is transferred to the turbine, making it rotate. The turbine then turns a generator to produce electricity, in addition to the electricity produced by the generator connected to the gas turbine. This is why this type of power plant is called a "combined cycle" or "dual cycle." The thermal efficiency of the overall combined cycle may be over 50%.²⁶

Condenser

After the steam exits the steam turbine, it flows through the condenser. The condenser is essentially a heat exchanger where the steam is cooled and condensed back into water by cooling water from the cooling tower. The cooling water from the cooling tower flows through the tubes in the condenser while the steam flows over the tubes. Condensed water from the condenser is then pumped from the condenser by the condensate pump to the feedwater pumps and back into the boiler.

Cooling Tower

The cooling tower is often used to cool the water that was used to condense steam in the condenser. Cooling towers are generally rectangular structures that may be divided into a few independent cells. Within the stack or body of a cooling tower is a large fan that draws air up through the cooling tower from the sides of the device. As air is being pulled up through the device, the warmed water from the condenser is sprayed down from the top of the tower. The water trickles down by gravity through the tower over baffles or packing, which help maximize the surface area of the water and the contact between the air and water. The air and water also move in a counter-flow arrangement which helps improve contact between the two flows. Heat is primarily removed from the water through evaporation of water in the cooling tower. This process is also

THEORY & OPERATION

Gas Turbines

called evaporative cooling. Cooled water falls to the bottom of the cooling tower in a basin, where it can then be pumped to the condenser to continue condensing steam.

Depending on the weather conditions, a plume may often be seen from the stack of a cooling tower. A plume is more likely to be seen with lower air temperatures and higher humidities. Cold air cannot hold as much water as warm air, so when warm moist air leaves the stack of a cooling tower, condensation will occur if the air is cold enough. Under humid conditions a water vapor plume may form because the air can't hold any more water. Since water is continually lost to the atmosphere from the stack of the cooling tower, make-up water is added to the system.

Not all gas turbines are equipped with steam turbines. Some of them simply use the heat recovery steam generator to produce steam for steam injection. Some plants may be equipped with simple cycle peaking turbines to produce power during high energy demand periods.

207.1 DUCT BURNER OPERATION

As mentioned earlier, many cogeneration or combined cycle gas turbine power plants use a duct burner to increase the steam capacity of the HRSG and power output. Duct burners usually burn natural gas, but they may also burn oil. Duct burners can almost double the temperatures of exhaust gases in the HRSG to 2000°F, but most duct burners are run to increase temperatures in the neighborhood of 1400°F.

Different design of duct burners exist, but Figure 207.2 illustrates a cross-sectional view of a low NOx duct burner that burns natural gas. Exhaust gases from the gas turbine flow around the fuel manifold and mix with the natural gas flowing from orifices in the manifold. The zone around the fuel manifold (zone A) is a fuel rich zone since only a small amount of exhaust gases can pass through the small slot between the manifold and the stabilizer casing of the duct burner. A "diffusion flame" burns in zone "A" forming a recirculation pattern. When exhaust gases flow into zone "B" they mix with combustion products from the turbine, more eddies are formed behind the stabilizer casing and combustion is completed.

Water Vapor Plumes

June 1996 200 - 57

THEORY & OPERATION

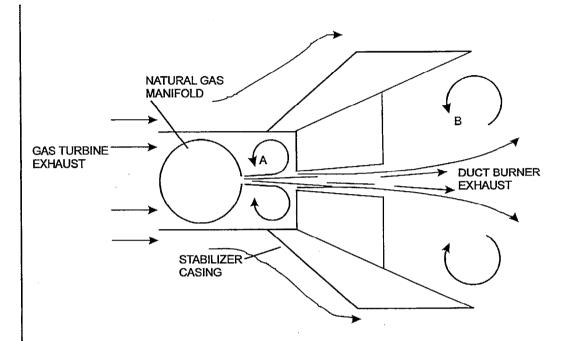


Figure 207.2 Top, Cross-sectional View of Duct Burner

208 AIRCRAFT GAS TURBINES - JET ENGINES

As with all means of motion, jet propulsion is based on Newton's Second and Third Laws of Motion. The Second Law states that the rate of change of momentum in any direction is proportional to the force acting in that direction. The Third Law states that for every action there is an equal and opposite reaction. The momentum of a body is defined as its mass times its velocity. Therefore, to change the velocity of a body, a force is required. In an aircraft gas turbine or jet engine the engine draws in air, adds energy to it by burning fuel, and expels exhaust toward the rear at a much higher velocity. The jet engine produces a large change in velocity. The action of the exhaust coming from the rear of the engine causes a reaction in the opposite direction in the form of propulsive force. The propulsive force is also called thrust, and thrust from a jet engine is gauged in pounds-force (lbf).

THEORY & OPERATION

Gas Turbines

An example of action and reaction is the way a garden hose, laying unrestrained on the ground, is driven backward when the water is turned on and flows from the hose. The effect is even stronger when a nozzle is installed on the hose. Another example is the recoil that is felt when a gun is fired. The recoil of the gun is not from the gases being expelled from the gun. If a gun was fired in a vacuum the recoil would still be felt.

Jet Propulsion Examples

Furthermore, if a balloon filled with air was released it would fly through the air and it would also have the same motion if it was released within a vacuum. When the balloon is inflated it has a pressure inside that is higher than atmospheric pressure. This pressure acts equally on all parts of the balloon. If the valve of the balloon is allowed to open the pressure at the valve becomes zero because there is no balloon wall for the air to push against. On the side of the balloon opposite the valve the air pressure inside the balloon still pushes against the balloon. This "unbalanced" force on the balloon causes the balloon to move through the air. This illustrates that the cause of the motion is not the escaping air pushing against air molecules outside the balloon.

The thrust force that drives a jet engine is somewhat like the thrust force that drives a balloon. The energy from burning fuel in the combustor is used to run the compressor of the engine. The compressor creates a high pressure on its downstream side. The nozzle of the engine is opposite the compressor and it is open, so the pressure inside the engine has nothing to push against at the nozzle. The pressure at the nozzle is nearly atmospheric pressure or zero gauge pressure. The unbalanced force from the high pressure in the engine is the thrust force that pushes the engine through the air.

208.1 TYPES OF JET ENGINES

Figure 208.1 illustrates the main types of jet engines used for aircraft. They include the turbojet, turbojet with afterburner, turboprop, turbofan, ram jet, and rocket. Most jet engines are essentially gas turbines. Although rockets are not gas turbines, they are included in the figure since they are "jet engines." All gas turbines and atmospheric jet engines use atmospheric air to burn fuel, but rockets carry and use their own oxidizer to burn fuel.

June 1996 200 - 59

Figure 208.1 Jet Engines

208.1.1 Turbojet Engines

The turbojet engine is the most common jet engine (Fig. 208.2). Turbojet engines are gas turbines without any power turbines. Most stationary gas turbines are simply turbojet engines that have been retrofitted with power turbines and transmission shafting.

The net output power in a turbojet engine is in the form of the thrust force of the engine. The main purpose for the turbine in the turbojet engine is to drive the compressor to compress air for combustion. A turbojet engine will have fewer turbine stages than a stationary gas turbine, since it only needs to extract energy from the exhaust gas for the compressor.

As with the stationary gas turbine, the turbojet engine can be the centrifugal or axial type. The type of compressor on the engine determines whether it is axial or centrifugal. In the centrifugal type, the compression of the entering air is by centrifugal force. In the centrifugal engine, air enters the impeller of the compressor and is thrown outward in a radial direction, increasing the velocity of the air. As the air flows through the diffuser of the compressor, its velocity is decreased with a corresponding increase in pressure.

Almost all turbojet engines are the axial type of engine. In the axial turbojet engine the air flows axially; it takes a relatively straight path through the engine in the same direction as the "axle" of the compressor. Some of the reasons turbojet engines use the axial design are: less energy is lost in the compressor

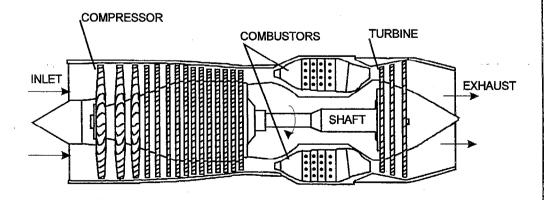


Figure 208.2 Single Spool TurboJet Engine

THEORY & OPERATION

since the air moves in a relatively straight direction through it, a higher pressure ratio can be achieved since successive compressor stages can be utilized, and the frontal area can be reduced with the same volume of air consumed.

Mach Number

A turbojet engine can be used for subsonic or supersonic applications. Subsonic conditions are those where the air velocity at the point in question is less than the speed of sound. A term called the "Mach number" is used to define the conditions of air flow. The Mach number is the velocity divided by the speed of sound at the point in question.

M = v/c

where:

M = Mach number

v = Velocity (ft/sec)

c = speed of sound (ft/sec)

If M is less than 1.0 the conditions of the flowing air are subsonic, and if M is equal to 1.0 the conditions are sonic. Supersonic conditions are attained when the Mach number is greater than 1.0 but less than 5.0. Turbojets are the type of engines used by supersonic jets. Military fighter jets and the Concord (a French airliner) have supersonic capability; they can fly faster than the speed of sound.

208.1.2 Turbojet with Afterburner

A turbojet engine with an afterburner is almost the same as a regular turbojet engine except it has an afterburner section that behaves as a second combustion chamber (Fig. 208.3). It is essentially a gas turbine with reheat, but no turbine wheels exist after the afterburner. When an afterburner is turned on in a gas turbine, fuel is dumped into the hot exhaust gases in the section after the turbine and ignited. Flame holders are required to prevent the flame from being blown out of the back of the engine.

The afterburner dramatically increases the output power of the engine in a very short period of time. The thrust from the engine will increase 50 to 70%. The afterburner uses a large amount of fuel and it produces a larger amount of emissions. Although there is a large amount of unburned oxygen in the exhaust gases that provide adequate combustion, incomplete combustion occurs and there are increased pollutant emissions.

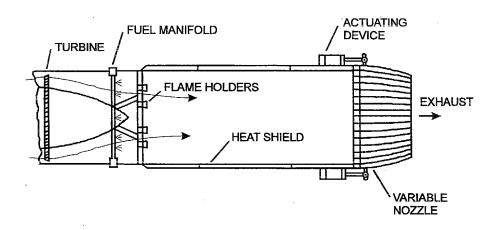


Figure 208.3 Afterburner Section of Gas Turbine

The afterburner is equipped with a nozzle at the back end that can be narrowed by the pilot to increase the velocity of the gases leaving the engine. The nozzle is perforated to provide cooling.

208.1.3 Turboprop Engine

Turboprop engines are gas turbines that are used to drive the propellers in propeller driven aircraft. Earlier this century, before the development of jet aircraft, reciprocating internal combustion engines were the only engines used to drive the propellers for aircraft. Because of the advantages of the gas turbine, practically all propeller driven airliners and propeller driven military aircraft now use turboprop engines. Today, reciprocating aircraft engines are primarily used for small, privately-owned aircrafts. The turboprop engine has more power output relative to its weight than reciprocating engines, making it an excellent power plant for aircraft.

The net output work of the turbine in a turboprop engine is used to turn a shaft which drives the propeller for the aircraft. The turboprop engine has extra turbine stages (turbine wheels) to extract most of the energy from the exhaust gases and convert it into shaft horsepower (Fig. 208.4). In general, only 10 to

June 1996

THEORY & OPERATION

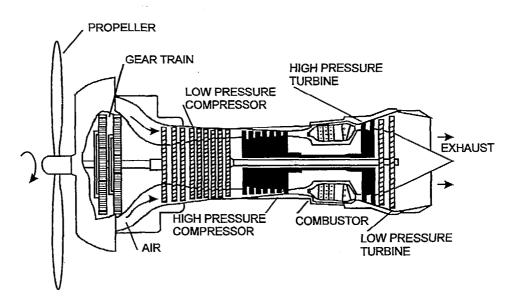


Figure 208.4 Turboprop Gas Turbine Engine

20% of the thrust from the exhaust of the engine is used for propulsion, but in some engines the exhaust may provide little thrust at all. Not only does the turbine drive the propeller, it also drives the compressor.

Because of the dynamics of the air flow over the propeller, there is a limit to how fast the propeller can rotate. The maximum speed occurs when the relative velocity of the air flowing over the propeller reaches the speed of sound, or in other words when the Mach number equals one. As stated earlier the Mach number is the ratio of the velocity to the speed of sound. Sonic conditions (where the Mach number is one) will first be attained at the tips of a propeller, since the further from the center of the propeller a given point is, the higher the velocity. Once the relative velocity of the air over the propeller becomes sonic, the dynamics of the air flow become unfavorable. A shock wave forms in the air and there is a decrease in the air pushed back by the propeller.

In order to help keep the rotational velocity of the propeller from getting too high, the shaft connecting the turbine and compressor is connected to a gear train. The gear train reduces the rotational speed of the propeller. The rotational input from the turbine goes into the gear train and the reduced rotational output from the gear train goes to the propeller. In the past, when most propeller driven

aircraft were equipped with reciprocating engines, they were equipped with large propellers, because the reciprocating engines had high torques but relatively lower rotational outputs (lower rpm's, revolutions per minute). The larger propellers had a high velocity toward the tip, and more thrust force can be attained with higher velocities until sonic conditions are achieved. Turboprop engines have higher rpm's with relatively lower torque, so the propeller can be smaller in diameter.

A variation of the turboprop engine, known as the turboshaft engine, is used as a power plant for helicopters. In general a turboshaft engine will have a larger gear reduction, because it drives a helicopter blade which is much larger than a propeller, but it operates similar to a turboprop.

Turboshaft Engine

208.1.4 Turbofan Engine

The turbofan engine is essentially a cross between the turbojet engine and the turboprop engine. The turbofan engine is equipped with enlarged compressor wheels or "fans" ahead of the compressor (Fig. 208.5). Not only does the fan act as an extra compressor stage before the low pressure compressor, it provides

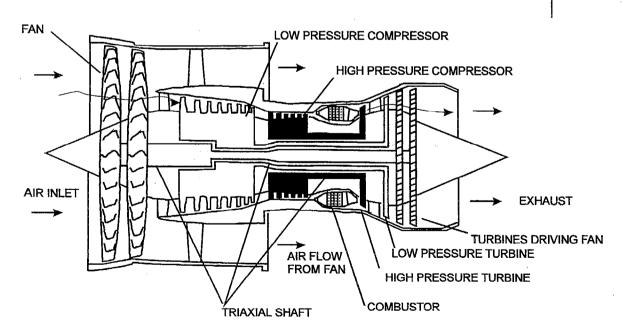


Figure 208.5 Turbofan Gas Turbine Engine

THEORY & OPERATION

propulsion in a manner similar to a propeller. Both the low pressure compressor and the fan may turn on the same shaft, or the fan and low pressure compressor can be on separate shafts. If the fan and low pressure compressor are on the same shaft the engine will have a coaxial, dual shaft design. If the fan and low pressure compressor are driven by separate shafts, the engine will have three shafts (one within another) and three turbines. The fan may also be called the low pressure compressor; therefore, the next two compressors are called the intermediate pressure compressor and the high pressure compressor.

Some turbofan engines have been designed with the fan on the back part of the engine near the turbine, but practically all engines have the fan in front. The main advantages of the turbofan design are that it provides an increase in the power to weight ratio of the engine and it improves the thrust specific fuel consumption.²⁷

A small percentage of the exhaust gases flowing from the back of the engine also provide thrust for propulsion. Most of the air that flows through the fan does not flow through the compressor but it is used to provide propulsion. Air for combustion and cooling in the gas turbine also flows through the fan. The ratio of the air that by-passes the gas turbine to the air the flows through the gas turbine is approximately 8:1 or more.

A turbofan engine looks similar to a turbojet engine, but the two can be distinguished by the large cowling in the front part of the engine, followed by the narrower body of the engine, which consists of the main part of the gas turbine. The gas turbine on the cover of this manual, for example, is a turbofan.

The turbofan engine is generally used to power large sized aircraft, including airliners and military transport aircraft. Turbofan and turbojet engines also tend to have different sounds during operation. Turbofans, especially large-sized engines, have more of a whirling sound while turbojets have a more of a "rocket-like" sound. Turbofan engines are used for subsonic applications (less than the speed of sound).

200 - 66 June 1996

208.1.5 Ram Jet

The ram jet, also known as the Lorin tube, was named after Rene Lorin, a French engineer who is credited with inventing and patenting the first ram jet in 1913. It is a steady flow or steady combustion engine with the simplest construction of any propulsion engine (Fig. 208.6).

Compression of air entering the ram jet occurs only by "ram compression" due to the absence of a compressor. The velocity of the air entering the engine and the shape of the inlet diffuser act to compress the air. A high air velocity entering the ram jet is required for the engine to run. The ratio of the pressure exiting the diffuser to the inlet pressure to the engine is the ram pressure ratio. This is analogous to the pressure ratio from a gas turbine. The higher the velocity entering the ram jet, the higher the ram pressure ratio.

Before any thrust is produced by a ram jet, a speed of 300 miles/hour must be attained, and a much higher speed must be reached before the thrust produced exceeds the drag force on the engine.²⁸ A ram jet is brought up to this velocity by a turbojet engine. The ram jet is usually used for supersonic applications. Once an aircraft reaches sufficient speed the ram jet engines can be started, providing additional power.

Since there is no turbine, higher temperatures can be used in the ram jet. A ram jet engine also has a lower weight because there is less equipment. At supersonic speeds the ram jet produces more thrust per unit engine weight than

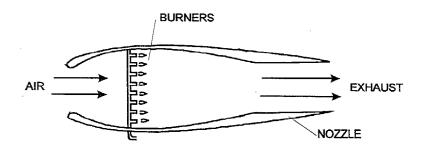


Figure 208.6 Ram Jet Engine Concept

THEORY & OPERATION

any other propulsion engine except rockets. The thrust per unit frontal area increases with efficiency and air flow through the engine; therefore, much more thrust per unit frontal area is possible at high supersonic speeds.

208.1.6 Rockets

Rocket engines are different from jet engines in that rocket engines have their own fuel and oxidizer. Jet engines need atmospheric air to operate, but rockets do not. Rocket engines also do not have compressor or turbine wheels. Rockets can be classified by the type of fuel they use, which includes solid propellent and liquid propellent.

208.2 AIRCRAFT VS. INDUSTRIAL GAS TURBINES

Since stationary gas turbines originally designed to operate for aircraft (aero-derivative gas turbines) are designed for a different purpose than "heavy duty" or "industrial" gas turbines, the two types of engines differ in many respects.

Weight is a large consideration for aircraft, so aero-derivative gas turbines are constructed with lighter weight alloys and they are not as bulky as heavy duty engines. Since heavy duty gas turbines have thicker heavier parts and they can handle more abuse and mechanical shock. An object that gets drawn into a heavy duty engine may not do any significant damage to it, but if an object gets drawn into a aero-derivative engine, it is much more likely to do severe damage.

On the other hand, aero-derivative engines are more efficient than heavy duty gas turbines. Aero-derivative gas turbines may have efficiencies as high as 40%, but heavy duty gas turbines generally have efficiencies around 32 to 34%. Aero derivative engines run at higher temperatures and they are able to withstand more thermal shock.

The throttle on Aero-derivative gas turbines can be varied as it is on aircraft engines. Stationary gas turbines are run at full throttle, but aircraft engines are usually run at full throttle only during take-off and landing. Heavy duty gas turbines can only be run at full throttle. Stationary gas turbines run at 3600 rpm which is equivalent to 60 Hz.

THEORY & OPERATION

Gas Turbines

The aero-derivative gas turbines used in today's power plants are usually the dual compressor type, with a high pressure compressor and low pressure compressor with a corresponding high turbine and low pressure turbine. Heavy duty gas turbines usually do not have a dual compressor. Heavy duty engines often have the turbine or compressor directly connected to a generator for the electrical output, but aero-derivative engines have a power turbine that is connected to a generator. The power turbine is retrofitted to the aero-derivative engine and it is not directly (or mechanically) connected to the low pressure turbine of the engine. The exhaust gases from the aero-derivative gas turbine that would normally be the thrust in aircraft applications turns the power turbine.

June 1996 200 - 69

.3	

Gas Turbines

This section describes the emissions from gas turbines and how they are controlled.

301 GAS TURBINE EMISSIONS

Air pollution emissions from gas turbines are almost exclusively from combustion, but there is a potential for emissions from the storage of the fuel for a gas turbine. Combustion emissions from a gas turbine include nitrogen oxides (NOx), sulfur dioxides (SOx), carbon monoxide (CO), un-burned hydrocarbons, and particulate matter. The storage of fuels can be potential sources of emissions because volatile hydrocarbons or volatile organic compounds (VOCs) can escape from storage and enter the atmosphere. Overall, NOx and CO are the most significant emissions from gas turbines.

Natural gas is the fuel often used for a stationary gas turbine, and it is usually delivered to a plant via a pipeline and generally isn't stored at a plant in large quantities. Methane (CH_4) is the main gas component in natural gas, and natural gas contains various amounts of ethane (C_2H_6) . Methane is a greenhouse gas but it is not considered to be a VOC. Ethane is not considered to be a volatile organic compound by the Environmental Protection Agency (EPA), but it is a reactive organic compound (ROC) according to the Air Resources Board.

A variety of petroleum distillates from heavier fuels to light gases can be used to run a gas turbine. These fuels include diesel, kerosene, jet fuel, gasoline, propane, butane, methane and others. The storage of gasoline is a source of volatile organic compounds emissions. Diesel fuel is sometime used as a backup or emergency fuel for a gas turbine, but its vapor pressure at ambient conditions is low enough to prevent problems with VOC emissions.

301.1 NOX EMISSIONS

Nitrogen oxide (NOx) emissions are the main pollutant from gas turbines. Nitrogen oxides include nitrogen dioxide (NO₂) and nitrogen oxide (NO). 90% to 95% of the nitrogen oxides that form from a combustion process are in the form of nitrogen oxide (NO), but nitrogen oxide can later photochemically react to form nitrogen dioxide (NO₂). Nitrous Oxide (N₂O) can also form from NOx control processes and is sometimes a concern. All total there are actually seven

June 1996 300 - 1

EMISSION CONTROL

NOx Compounds

known oxides of nitrogen which includes NO, NO₂, N₂O, NO₃, N₂O₃, N₂O₄, and N₂O₅, but only nitrogen oxide, nitrogen dioxide and sometimes nitrous oxide are produced in high enough concentrations to be considered pollutants.

The combustor is the source of NOx emissions from gas turbines, but cogeneration and dual cycle power plants usually have a duct burner which is an extra source of NOx emissions in the heat recovery steam generator (HRSG). The quantity of NOx emissions from the duct burner is fixed and is independent of the combustor operation.

There are three main mechanisms in which NOx is formed in the combustors of gas turbines. The first mechanism is due to the nitrogen in the air. Atmospheric air is composed of 78% nitrogen, 20.9% oxygen, and a 1% total of carbon dioxide, water vapor, argon, helium and a very small percent of other inert gases. For most combustion applications, all the atmospheric components are grouped with nitrogen, making air composed of approximately 20.9% oxygen (O_2) and 79.1% nitrogen (N_2) by volume. In terms of mass, the atmosphere is approximately 76.85% nitrogen and 23.15% oxygen.

In perfect, ideal combustion the only exhaust products are carbon dioxide and water. When methane is burned with oxygen the following reaction occurs:

$$\mathbf{CH}_4 + \mathbf{O}_2 - \mathbf{CO}_2 + 2\mathbf{H}_2\mathbf{O}$$

One molecule of methane requires one molecule of oxygen to burn completely and will yield one molecule of carbon dioxide and two molecules of water. This is called stoichiometric combustion. The chemical reaction also indicates the volumes required for stoichiometric combustion. For example, one ft³ of methane will require one ft³ of oxygen to burn completely. In the real world atmospheric air, which is mostly nitrogen, is used for combustion, and the nitrogen will react with oxygen in the air, forming NOx compounds. The reaction between atmospheric nitrogen and oxygen is especially prevalent at higher combustion temperatures. This NOx formation mechanism is called **thermal NOx** and it is sometimes referred to as the "fixation of atmospheric nitrogen."

Thermal NOx

Gas Turbines

The second NOx formation mechanism during combustion processes is due to the nitrogen content of the fuel. When a fuel is burned, any nitrogen in the fuel can react with atmospheric oxygen, forming NOx compounds. The nitrogen in the fuel is called **fuel bound nitrogen (FBN)** and it is chemically bound in the fuel. Sometimes fuel bound nitrogen is called "organic NOx."

Fuel Bound Nitrogen

Most types of natural gas and light petroleum distillate oils have little or no fuel bound nitrogen.² Lower quality, heavier petroleum distillates, process gases, sewage gases, and low Btu coal gases (from gasifiers and hot gas clean-up) contain more fuel bound nitrogen. Coal may be heated in an oxygen deficient atmosphere to form combustible gases such as coke-oven gas or producer gas, which can be used as a fuel source. Compounds in fuels that contain nitrogen tend to reside in asphalt or heavy resin fractions in the fuel that managed to slip through refining processes. In general, when a fuel is burned with excess air (which is usually the case) higher NOx emissions will occur with higher concentrations of fuel bound nitrogen.

The nitrogen content of most U.S. coals is between 0.5 to 2 %, for residual oils the nitrogen content is between 0.1 and 0.5 %, and most distillate oils have a nitrogen content under 0.015 %.³

In the early 1970's, before regulations for gas turbine emissions were developed, gas turbine fuels generally contained almost no fuel bound nitrogen. Today, especially in the northeastern United States, some sources of petroleum distillates are from broader, lower quality crude oils. These fuels contain higher amounts of fuel bound nitrogen above 0.015 %.⁴

Gaseous fuels that contain higher molecular weight compounds (i.e. ethane, propane, and butane) will tend to burn hotter and therefore produce more NOx. On the other hand, gaseous fuels that contain higher amounts of inert gases such as carbon dioxide, will produce less NOx because the inert gas will tend to absorb some of the heat from combustion. Flame temperatures will be somewhat lower so less NOx is produced.

The third and less prominent NOx formation mechanism is from intermediate hydrocarbons present in the flames during the combustion process oxidizing to form NOx compounds. NOx from this mechanism is called "**prompt NOx**."

Prompt NOx

EMISSION CONTROL

Prompt NOx is an important consideration for gas turbines running to attain ultra-low emission levels. Below are chemical reactions involved in the formation of prompt NOx:

#1
$$CH + N_2 = HCN + N$$

#2
$$CH2 + N_2 = HCN + NH$$

#3 HCN, N, NH + Ox
$$\Rightarrow$$
 NO + ...

Zeldovich Mechanism

The sequence of the chemical reactions involved in the formation of thermal NOx is known as the Zeldovich mechanism.⁵ As mentioned earlier, higher combustion temperatures create higher amounts of NOx compounds. The Zeldovich mechanism shows that the formation of thermal NOx is an exponential function of the flame temperature. It also shows that the NOx generated is a line function of the time that flue gases remain at the flame temperature.⁶ Therefore, the amount of NOx formation is not only dependent on the temperature of the combustion process, but it is also dependent on the residence time in the combustor of the gas turbine.

Below is listed the sequence of chemical reactions that form NOx under lean air fuel mixtures (with an excess of oxygen) according to the Zeldovich mechanism:⁷

#1
$$O_2 = 2O$$

#2 $N_2 = 2N$
#3 $N + O = NO$
#4 $N + O_2 = NO + O$

$$\#5 \text{ O} + N_2^2 = \text{NO} + \text{N}$$

Under fuel rich condition (with excessive fuel and a deficit of oxygen) additional chemical reactions occur:

In an actual operating combustor all of the above chemical reactions will occur because of imperfect mixing of the fuel and air. At any moment in time some parts of a combustor may be lean while others may be rich.

Gas Turbines

The residence time is the amount of time it takes the burning gases to flow through the combustion chamber. The longer the residence time is, the more NOx emissions that will be created. The residence time can be decreased by shortening the length of the combustor. In general, maximizing the three T's of combustion (time, temperature and turbulence) provides for efficient combustion. Reducing the residence time can lead to incomplete combustion (increased carbon monoxide (CO) emissions), increased emissions of unburned hydrocarbons and other problems.

Figure 301.1 illustrates how uncontrolled NOx emissions vary from a conventional combustor with different turbine inlet temperatures. Note that when the combustor runs on No.2 fuel oil, the emissions of NOx are higher since it is a heavier fuel than natural gas. Distillate oils generally burn with

since it is a heavier fuel than natural gas. Distillate oils generally burn with flame temperature 100°F higher than natural gas, with all other parts of the system constant. Since NOx formation is a function of temperature, the higher temperature increases NOx emissions. Furthermore, the distillate fuel has a

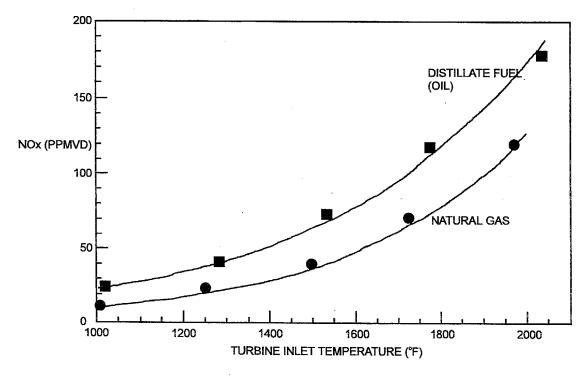


Figure 301.1 NOx vs. Turbine Inlet Temperature

Residence Time

EMISSION CONTROL

Equivalence Ratio higher nitrogen content. Heavier, higher molecular weight fuels tend to have a higher nitrogen content. Also note that the NOx emissions rise rapidly with increasing temperature for both fuels.

Figure 301.2 shows NOx emissions and flame temperature versus equivalence ratio. The equivalence ratio is the ratio of fuel burned in the flame to the amount of fuel that would be burned if all the oxygen was consumed.⁹ Therefore, a value of 1 in equivalence ratio is stoichiometric combustion.

A flame burns its best when it has just enough fuel to react with the oxygen that is available, but the highest theoretical flame temperature is attained slightly above stoichiometric. Close inspection of Figure 301.2 shows that the highest temperature is reached just above an equivalence of 1. This highest point in temperature is called stoichiometric adiabatic flame temperature. When the fuel/air mixture has more fuel than air relative to stoichiometric, the mixture is rich. An excessively rich fuel/air can lead to the formation of smoke. A lean fuel/air mixture is one that does not have enough fuel or has too much air. A lean mixture will tend to produce more carbon monoxide (CO) emissions due to lower temperatures.

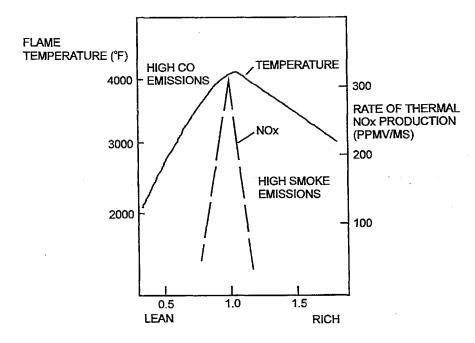


Figure 301.2 Thermal NOx vs. Equivalence Ratio

Gas Turbines

Gas turbines are run with a lean fuel/air ratio. They are not run at the highest theoretical flame temperature because the materials of the turbine cannot withstand the high temperatures. This limit typically corresponds to an equivalence ratio of 0.4 to 0.5 (40% to 50% of stoichiometric). Proper controls are required because a gas turbine will not operate well at such an air/fuel ratio since it will not burn efficiently and stably. The combustor is controlled so that only a portion of the air is mixed with the fuel at any one time. The rest of the air is used to cool the gases before entering the turbine, and to cool the combustor.

301.1.1 Other Factors Affecting NOx Emissions from Gas Turbines

Atmospheric Conditions

The atmospheric conditions that affect NOx emissions are humidity, temperature and pressure. Water vapor in atmospheric air tends to have a quenching effect on combustor temperatures. Energy is required to heat the water vapor in atmospheric air and lower temperatures in the combustor create less NOx.

At low humidities NOx emissions increase with higher ambient temperatures, but at higher humidities, the amount of NOx emissions varies with different temperatures. When the humidity is high and the temperature is relatively low, NOx emissions increase with increasing temperature. When the humidity is high and the temperature is higher (above 50°F) NOx emissions decrease with increasing temperatures.

NOx emissions are higher with higher ambient pressures. With higher pressures, the temperature and pressure in the combustor will tend to be higher so more NOx is produced. Humidity is the atmospheric parameter which has the greatest effect on NOx formation.

Below is a relation that can be used to correct the influence of ambient conditions on measured NOx levels:¹¹

 $NOx = (NOxo)(Pr/Po)^{0.5exp19(Ho-0.00633)}(288^{\circ}K/Ta)^{1.53}$

where:

NOx = Emission rate of NOx at 15% O_2 and International Standards Organization (ISO) ambient conditions, volume percent.

Humidity

Pressure

EMISSION CONTROL

NOxo = Observed NOx concentration, (ppmv) referenced to 15% O_2 . Pr = Reference compressor inlet absolute pressure at 101.3 KPa ambient pressure, (mmHg)

Po = Observed compressor inlet absolute pressure at test, (mmHg)

Ho = Observed humidity of ambient air, g H₂O/g air

Ta = Ambient temperature, °K

Power Output Level

The output power of a gas turbine is directly related to the firing temperature. The firing temperature is directly related to the flame temperature and lower temperatures produce less NOx emissions. Gas turbines have rated power outputs with corresponding NOx emissions amounts. At power outputs below the rated value NOx emissions are lower, but at power outputs above rated NOx emissions are higher.

Operating Cycle

If a gas turbine was operated with a reheat cycle emissions would be higher, because the additional combustor is another source of NOx emissions. Gas turbines with regenerators will have higher NOx emissions because of the increased combustor inlet temperatures.

Duct Burners

Cogeneration and dual cycle gas turbines will produce additional NOx if they have a duct burner. In general a duct burner will produce 0.1 pounds of NOx for every million Btu of fuel burned. The concentration of NOx added by a duct burner burning natural gas are 10 to 30 ppmv @ 15% O_2 for gas turbines with an output between 3 and 50 MW and 5 to 10 ppmv @ 15% O_2 for gas turbines with an output over 50 MW.¹²

301.1.2 NOx Effects on Health and the Environment

The nitrogen dioxide (NO₂) is the pollutant form of NOx that is of primary concern. Nitrogen dioxide is a gas at ambient conditions and has a brownish color. The brownish haze seen over large cities is partially due to nitrogen dioxide. Most of the combustion emissions of NOx are in the form of nitrogen oxide (NO), but nitrogen oxide photochemically reacts from the energy of

Gas Turbines

sunlight to form nitrogen dioxide. NOx also contributes to photochemical reactions that create ozone (O₃), historically California's worst pollution problem.

Nitrogen dioxide is a reactive chemical and it is immediately dangerous to life and health (IDLH) at 50 ppm. At higher concentrations it causes coughing, chest pain, and eye irritation. The State ambient air quality standard for nitrogen dioxide is 0.25 ppm for one hour. The federal standard is an annual average of 0.053 ppm. Over 8.5 million Americans live in counties with levels of NOx over the federal ambient air quality standards.

Nitrogen dioxide damages the cells lining the respiratory tract and increases a person's susceptibility to respiratory infection. It also constricts the airways of asthmatics. Studies also show that mice injected with cancer cells develop more tumors when exposed to nitrogen dioxide. Other studies with animals show that NO₂ adversely affects the kidneys, liver, spleen, red blood cells and immune system cells.

NOx compounds also contribute to the formation of acid rain and contribute to the depletion of the ozone layer. In the eastern U.S., 1/3 of the acid rain during a full year and 1/2 the acid rain in the winter is from NOx emissions.¹³ Nitrogen oxides contribute to the nitrification of rain which can lead to an "overfertilizing" effect on the soil. This excessive fertilizing can make foliage more vulnerable to damage from cold weather, insects, and disease. NOx compounds also have a heat-trapping tendency and therefore contribute to global warming.

301.2 CARBON MONOXIDE EMISSIONS

Carbon Monoxide (CO) is emitted from gas turbines and other combustion devices from incomplete combustion. Incomplete combustion can occur when there is too much fuel or not enough air in a combustion process. Incomplete combustion can also occur from insufficient fuel and air mixing, and excessively low combustion temperatures. Smoke is a sign of incomplete combustion. Carbon Monoxide (CO) forms instead of carbon dioxide (CO₂) in incomplete combustion.

Acid Rain

June 1996 300 - 9

EMISSION CONTROL

As with the emissions of NOx compounds, carbon monoxide emissions are a function of temperature. Figure 301.3 illustrates how carbon monoxide emissions decrease with increasing turbine inlet temperatures. Therefore, there is a conflict in terms of temperature for carbon monoxide and NOx emissions. High temperatures will produce more NOx and less carbon monoxide, but lower temperatures will produce less NOx and more carbon monoxide.

301.2.1 Carbon Monoxide Health Effects

Hemoglobin

When drawn into the lungs, carbon monoxide binds tightly to hemoglobin, a oxygen carrying protein in the blood. Carbon monoxide binds tighter to hemoglobin than oxygen; therefore, oxygen is unable to bind to the hemoglobin, less oxygen enters the blood and less oxygen can reach the cells of the body. Every cell in the human body requires oxygen to stay alive.

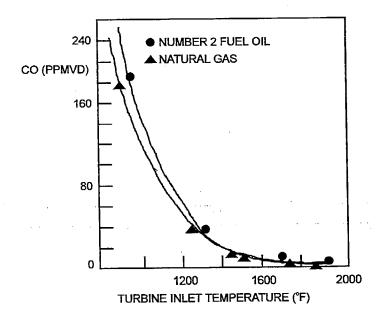


Figure 301.3 Carbon Monoxide vs. Turbine Inlet Temperature

Gas Turbines

Exposure to carbon monoxide can cause headaches, fatigue, and slowed reflexes. Higher concentrations can cause nausea, confusion and hallucinations. Carbon monoxide is especially dangerous to people with coronary artery disease since their hearts receive limited supplies of oxygen.

Carbon monoxide is immediately dangerous to life and health at 1500 ppm. The State ambient air quality standard for carbon monoxide is 9.0 ppm for 8 hours or 20 ppm for one hour. The federal ambient air quality standard is 9.0 ppm for 8 hours and 35 ppm for 1 hour. California also has a separate standard for carbon monoxide in the Lake Tahoe air basin of 6 ppm for 8 hours. California has a stricter standard for carbon monoxide in the Lake Tahoe air basin because at the high elevation of the air basin the air is thinner and there is less oxygen to breathe. Carbon monoxide health effects are worse there because of the decrease in available oxygen.

Carbon monoxide is a pollutant that is directly emitted into the atmosphere, and it is not created photochemically as is NOx, but problems with carbon monoxide tend to be worse in the winter months. Photochemical pollutants such as ozone and NOx tend to be worse in the summer months when there is more sunshine. Over 18,000 tons per day of carbon monoxide are released into California's atmosphere, and 90% of the emissions are from motor vehicles.

301.3 SULFUR OXIDES (SOX)

Sulfur oxides (SOx) are primarily sulfur dioxide (SO₂) but also include sulfur trioxide (SO₃). Sulfur dioxide comes from the combustion of fuels with sulfur in them. Sulfur compounds occur naturally in crude oils and most fuels are derived from petroleum. Unless the sulfur is removed, the sulfur in the fuel will also burn, forming sulfur dioxide and other sulfur compounds. Crude oils with high amounts of sulfur compounds are called "sour" crudes and crude oils with low amounts of sulfur are called "sweet" crudes. Sulfur burning in a fuel contributes to its energy output, but sulfur in a fuel is undesirable because it can cause corrosion of combustion equipment and because of the SOx emissions. Sulfur compounds can also be found in natural gas in the form of hydrogen sulfide (H₂S). Natural gas can be processed to remove sulfur compounds after it is recovered from a well. Sulfur compounds are also usually present in solid fossil fuels such as coal.

Sour Crudes

Hydrogen Sulfide

EMISSION CONTROL

301.3.1 Sulfur Dioxide Health and Environmental Effects

Inhalation of sulfur dioxide can cause shortness of breath in people with asthma. It also adversely affects people with emphysema and chronic bronchitis. Higher levels of sulfur dioxide can cause healthy people to experience sore throats, coughing and breathing difficulties. The effects of sulfur dioxide are made worse by particulate matter and/or moisture. This is called a synergistic effect. Sulfur oxide emissions also contribute to acid rain.

Primary & Secondary Standards

The State ambient air quality standards for sulfur dioxide are 0.05 ppm over 24 hours or 0.25 ppm over 1 hour. The federal (primary) ambient air quality standards are an annual average of $80 \,\mu\text{g/m}^3$ (0.03 ppm) or $365 \,\mu\text{g/m}^3$ (0.14 ppm) over 24 hours. The federal standards also have a secondary standard of $1300 \,\mu\text{g/m}^3$ (0.5 ppm) over 3 hours. Primary federal standards are made to protect public health and secondary standards are made to protect public welfare.

301.4 HYDROCARBON EMISSIONS

Hydrocarbons are compounds made of carbon and hydrogen atoms, and fuels are mostly made up of different hydrocarbons. Many hydrocarbons are also volatile organic compounds (VOCs). VOCs are organic (carbon-containing) compounds that evaporate at a high rate at a low temperature. Hydrocarbon emissions from gas turbines are a concern because volatile hydrocarbons can contribute to the formation of ozone (O₃) and ozone has been California's worst pollution problem. Ozone is a photochemical pollutant; it is formed by chemical reactions from the energy of sunlight, hydrocarbons, and nitrogen oxides.

The potential sources of hydrocarbons from gas turbines are from the storage of fuel for a gas turbine and the unburned hydrocarbons from the exhaust. Emissions of unburned hydrocarbons from gas turbines is very low and the hydrocarbons that make up natural gas are not considered to be ozone precursors. On the other hand ethane, which is in different natural gases in varying amounts, is considered to be a reactive organic compound by the Air Resources Board, and petroleum distillate fuels (gasoline, jet fuel, etc.) are sources of ozone precursors. Almost any petroleum distillate fuel can be used in a gas turbine.

VOCs

Ozone

Gas Turbines

Not only do emissions of volatile organic compounds in the atmosphere cause the formation of smog, but many VOCs are directly toxic or hazardous to a person's health. Although combustion sources, such as gas turbines, emit unburned hydrocarbons and other toxic compounds, most of the main sources of direct exposure to VOCs come from the handling of fuels, solvents, coatings, etc.

Exposure to VOCs can have specific acute (short term) and chronic (long term) effects. Acute health effects of VOCs include: irritation and burning of the eyes, skin, nose and throat; dizziness, headache, and nausea; and even respiratory arrest. Chronic effects caused by VOCs entering the blood stream through the lungs or skin include: permanent vision damage, liver disease, kidney disease, contact dermatitis, and nervous system disorders. Workers at facilities using VOC products (i.e. paints, solvents, coatings etc.) should have a permissible exposure limit (PEL) to VOCs, which is the amount of a compound that workers can be safely exposed to in an eight hour day.

PEL

301.4.1 Ozone Health Effects

Ozone is a very reactive chemical. When it forms in high concentrations in the lower atmosphere it damages plants, the lungs of people and the surfaces of cars and buildings.

Ozone attacks the leaves of plants and causes them to yellow, develop dead areas, and die. Ozone makes crops more susceptible to disease and insect attack and reduces their yield. Smog is estimated to cost California between 150 million to 1 billion dollars a year in crop damage.

Research sponsored by the Air Resource Board has shown that exposure to ozone damages the alveoli, the air sacs in the lungs where the exchange of oxygen and carbon dioxide between the air and blood takes place. This injury results in lung inflammation and changes in breathing. Repeated injury is thought to lead to permanent lung damage. Exposure to ozone can also cause burning sensations in the chest, throat, and eyes.

The State ambient air quality standard for ozone is 0.09 ppm over one hour, and the federal standard is 0.12 ppm over one hour.

Alveoli

June 1996 300 - 13

EMISSION CONTROL

301.5 PARTICULATE MATTER EMISSIONS

Particulate matter is small, liquid or solid particles of material that can easily become airborne. The burning of fossil fuels, wood, photochemical reactions and agricultural operations are all man-made sources of particulate matter pollution. Most of the particles that get into the atmosphere are from natural sources, but human activities are the main source of particulate matter in urban areas, where the most people are exposed to it. Man-made sources of particulate are of greatest concern, since they are a greater health risk and more people are exposed to man-made particulates. People in rural areas can also be exposed to particulates from farming activities, woodburning, poor weather conditions, and transport from urban areas.

PM10

The greatest concern is for the very small particles that are less than 10.0 microns or micro meters $(10.0 \times 10^{-6} \text{ meters})$ in diameter, since these particles can easily bypass the lung's natural filtering system. Particles of this size are also called "PM10." Micrometers may also be abbreviated as "µm" or simply "microns." The State ambient air quality standards for particulate matter are 30μg/m³ averaged over a year and 50 μg/m³ averaged over 24 hours. The federal ambient air quality standards are 150 μg/m³ for 24 hours or an annual arithmetic mean of 50 μg/m³.

Natural Sources

The major sources of natural particulate matter include forest fires, soil debris, volcanoes and ocean salt spray. Some forest and brush fires can be man-made. All types of burning are sources of particulate matter.

Fugitive dust is a type of particulate matter that originates primarily from human activities disturbing the soil. Unpaved roads, farming, construction, off-road vehicles, and mining are some of the major causes of fugitive dust.

Besides being directly emitted into the atmosphere, particulate matter can be created in the atmosphere by chemical reactions. Sulfur dioxide emissions and nitrogen oxide emissions released into the atmosphere can later develop into sulfate and nitrate particles respectively through chemical reactions. Any fuel used in a gas turbine containing sulfur compounds will emit sulfur oxides. Gas turbines can also produce large amounts of nitrogen oxides.

Gas Turbines

The major categories of man-made sources of particulate matter are stationary fuel combustion, industrial processes, and solid waste disposal. Combustion from stationary sources is responsible for 35 to 50% of the total particulate matter from man-made sources. ¹⁵ Gas turbines are stationary sources of fuel combustion, but particulate emissions are usually a small problem, especially compared to NOx emissions. Gas turbines often burn natural gas, which has little or no potential for particulate emissions. Heavier fuels such as distillate oil have a much higher potential to release particulates.

As liquid fuel is injected into the combustor of a gas turbine, the fuel is atomized into small droplets. When the liquid droplets enter the combustion chamber the volatile substances are vaporized and then oxidized, releasing energy. After volatile materials are vaporized and driven from the liquid state ash and char still remain. Ash is incombustible material and char is slow burning organic compounds. Most of the char may still burn during a combustion process, but ash and any remaining char can become particulate emissions when they exit a stack.

Particulates can also be formed from homogeneous nucleation and heterogeneous nucleation. During homogeneous nucleation, new particles are created from vapor phase materials cooling and condensing, forming particulates. When heterogeneous nucleation occurs, material collects on the surface of existing particles. Homogeneous and heterogeneous nucleation occur when substances in the exhaust cool below their dewpoint and condense. The gaseous materials in the exhaust that can nucleate and form particulates include organic compounds, metals, and metal compounds. Metal compounds such as mercury, lead, cadmium, and arsenic can nucleate, and most of these compounds can be found in solid fuels and liquid fuels. Many of these compounds are toxic; therefore particulates can become carriers of toxic compounds.

Metal compounds tend to nucleate first after combustion since they have higher dewpoints. As hot flue gases cool further as they flow through heat exchange equipment, organic compounds begin to condense. Particles created by homogeneous and heterogenous nucleation are very small, ranging from 0.05 to 1.0 microns.

Ash & Char

Homogeneous & Heterogeneous Nucleation

June 1996

EMISSION CONTROL

301.5.1 Particulate Matter Health Effects

Short term exposure to particulate matter can lead to coughing and throat irritation. Inhaled particles can irritate the respiratory tract, constrict airways and interfere with the mucous lining of the airways. Longer term exposures can lead to increased chances of developing bronchial disease, a disease of the lungs. Particulates can be composed of metals and toxic compounds or they may carry carcinogens such as dioxin or benzene. These particles can get deep into the lungs and increase the probability of cancer. The EPA now also believes that inhaling particulate matter contributes to up to 60,000 deaths a year in people with preexisting respiratory and heart ailments.

Particulate matter is a form of pollution that adversely reduces visibility. Some forms of particulate matter can damage the surfaces of buildings, the finishes of cars, and other objects.

302 QUANTITY OF CALIFORNIA GAS TURBINE EMISSIONS

This section contains tables created from 1993 emission inventory data showing estimates of emissions from gas turbines. The tables appear on pages 300-18 through 300-19. The emissions are categorized by air basin. Each air basin contains the following counties:

- 1. Great Basin Valleys: Alpine, Inyo, Mono
- 2. Lake County
- 3. Lake Tahoe: El Dorado, Placer
- 4. Mountain Counties: Amador, Calaveras, El Dorado, Mariposa, Nevada, Placer, Plumas, Sierra, Tuolumne
- 5. North Coast: Del Norte, Humboldt, Mendocino, Sonoma, Trinity
- 6. North Central Coast: Monterey, San Benito, Santa Cruz
- 7. Northeast Plateau: Lassen, Modoc, Siskiyou
- 8. Sacramento Valley: Butte, Colusa, Glenn, Placer, Sacramento, Shasta, Solano, Sutter, Tehama, Yolo, Yuba
- 9. San Diego
- 10. San Francisco Bay Area: Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, Sonoma

- 11. San Joaquin Valley: Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus, Tulare
- 12. South Central Coast: San Luis Obispo, Santa Barbara, Ventura
- 13. South Coast: Los Angeles, Orange, Riverside, San Bernardino
- 14. Southeast Desert: Imperial, Kern, Los Angeles, Riverside, San Bernardino

The types of pollutants in the tables are:

TOG (Total Organic Gas) - All the organic gas emissions from gas turbines. ROG (Reactive Organic Gas) - All the organic gas emissions that are reactive. These compounds are ozone precursors. The reactive organic gas emissions are included in the total organic gas emissions. From the emissions in the tables, it is evident that total organic gas emission are greater than the reactive organic emissions since some of the emissions are not reactive.

CO - Carbon monoxide.

NOx - Nitrogen oxides.

SOx - Sulfur oxides.

PM - Particulate matter.

The emission tables are: stationary gas turbines (Table 302.1), jet aircraft commercial (Table 302.2), jet aircraft military (Table 302.3), and jet aircraft civil (Table 302.4). All the emissions from jet aircraft are area sources except for the ones from the South Coast. An emission inventory in terms of point sources has also been created for the Southeast Desert Air Basin. The emissions from the South Coast are from the point source emission inventory. The emissions inventory for jet aircraft is emissions from the engines below 3,500 feet. It does not take an aircraft long to reach this altitude so most of the emissions are released near the airport.

Table 302.5 shows emissions factors from many of the major gas turbine manufacturers.^{15.1} Emissions can be calculated by multiplying the numbers in the last two columns by the power output at which the gas turbine is operating. For example, if the emission factor from natural gas is 0.5 lb NOx/MMBtu and the output power is 10 MMBtu/hr, the emissions would be (0.5 lb NOx/MMBtu)(10 MMBtu/hr) = 5 lb NOx/hr.

June 1996 300 - 17

Table 302.1 Stationary Gas Turbine Emissions (Tons/year)							
Air Basin	TOG	ROG	СО	NOx	SOx	PM	PM10
Mountain Counties	0.6	0.456	1.5	7.1	0.5	0.5	0.488
North Coast	0.0	0.0	0.5	0.3	0.2	0.0	0.0
N. Central Coast	15.6	3.187	27.7	79.2	0.3	6.2	6.163
Outer Cont. Shelf	8.8	2.298	43.3	114.5	4.6	5.7	5.65
South Coast	901	193.26	1541.6	3531.6	79.2	502.3	499.158
S. Central Coast	100.7	22.123	410.5	488.2	7.3	55.1	54.735
San Diego	202.4	41.982	349.4	670.0	14.0	102.5	101.867
S.E. Desert	288.9	240.835	762.6	1502.7	7.2	97.2	97.129
Bay Area	101.1	21.545	454.8	1201.7	153.3	64.0	63.584
San Joaquin	1057.1	216.132	2455.7	7920.3	58.6	509.4	506.331
Sacramento	55.1	11.884	646.3	1034.2	4.2	65.4	64.99
TOTAL	2630.2	753.7	6693.9	16549.8	329.4	1408.3	1400.1

Table 302.2 Jet Aircraft Commercial Emissions (Tons/year)							
Air Basin	TOG	ROG	СО	NOx	SOx	PM	
Great Basin	14.6	14.6	36.5	14.6	3.65	7.3	
Lake Tahoe	47.45	40.15	105.85	40.15	7.3	18.25	
North Coast	7.3	3.65	25.55	14.6	0	0	
N. Central Coast	43.8	36.5	138.7	80.3	7.3	7.3	
S. Central Coast	456.25	390.55	569.4	182.5	14.6	0	
San Diego	135.05	116.8	602.25	832.2	69.35	32.85	
S.E. Desert	96.7	83.4	273.4	134.35	13.85	15.0	
Bay Area	1788.5	1540.3	4949.4	3562.4	0	3.65	
San Joaquin	1755.65	1511.1	1945.45	423.4	47.45	10.95	
Sacramento	62.05	51.1	208.05	266.45	14.6	7.3	
South Coast	2678.2	2259.9	9470.0	3725.8	259.2	3.8	
TOTAL	7085.55	6055.35	18328.2	9273.1	433.65	95.45	

Table 302.3 Jet Aircraft Emissions - Military (Tons/year)							
Air Basin	TOG	ROG	CO	NOx	SOx	PM	
N. Central Coast	21.9	18.25	171.55	21.9	7.3	10.95	
S. Central Coast	124.1	105.85	233.6	109.5	25.55	43.8	
San Diego	839.5	722.7	1949.1	587.65	32.85	310.25	
S.E. Desert	2255.8	1945.55	6749.6	1376.05	200.75	1080.4	
Bay Area	405.15	350.4	824.9	135.05	21.9	284.7	
San Joaquin	3993.1	3438.3	11855.2	1295.75	248.2	1354.15	
Sacramento	664.3	573.05	1266.55	354.05	36.5	47.45	
South Coast	1918.3	1618.7	3203.9	727.4	90.5	608.0	
TOTAL	10225.8	8772.8	26254.4	4607.35	663.55	3739.7	

Table 302.4 Jet Aircraft Emissions - Civil (Tons/year)								
Air Basin	TOG	ROG	СО	NOx	SOx	PM		
Great Basin	7.3	7.3	240.9	0	0	0		
Lake County	3.65	3.65	94.9	0	0	0		
Lake Tahoe	14.6	14.6	459.9	0	0	0		
Mountain Counties	54.75	47.45	1693.6	7.3	0	3.65		
N. Central Coast	73	62.05	2175.4	7.3	3.65	3.65		
North East Plateau	3.65	3.65	175.2	0	0	0		
S. Central Coast	102.2	87.6	189.8	25.55	3.65	3.65		
San Diego	43.8	36.5	321.2	14.6	3.65	0		
S.E. Desert	87.9	76.95	1015.3	14.6	3.65	0		
Bay Area	135.05	116.8	1314.0	65.7	10.95	0		
San Joaquin	277.4	237.25	3449.25	98.55	18.25	7.3		
Sacramento	226.3	197.1	3401.8	87.6	14.6	7.3		
South Coast	87.3	73.8	1240.4	16.6	2.1	1.4		
TOTAL	1116.9	961.05	15771.6	341.45	64.15	26.95		

June 1996 300 - 19

EMISSION CONTROL

Table 302.5	Uncontrolled I	NOx Emi	ission Fact	ors from Co	mmon Gas	Turbines
Manufacturer	1	Output (MW)	NOx (ppm 15% O2	v) dry at	NOx (lb/MMBtu)	
			Natural gas	Oil (No.2)	Natural gas	Oil (No.2)
Asea Brown Boveri	GT8 GT10 GT11 N GT35	47.4 22.6 81.6 16.9	430 150 390 300	680 200 560 360	1.72 0.601 1.56 1.20	2.50 0.735 2.06 1.32
General Electric	LM1600 LM2500 LM5000 LM6000 MS5001P MS6001B MS7001EA MS7001F MS9001EA	12.8 21.8 33.1 41.5 26.3 38.3 83.5 123 150 212	144 174 185 220 142 148 154 179 176	237 345 364 417 211 267 228 277 235 272	0.577 0.698 0.742 0.882 0.569 0.593 0.618 0.718 0.706	0.871 1.27 1.34 1.53 0.776 0.981 0.838 1.02 0.864 1.00
GM/Allison	501-KB5 570-KA 571-KA	4.0 4.9 5.9	155 101 101	231 182 182	0.622 0.405 0.405	0.849 0.669 0.669
Siemens	V84.2 V94.2 V64.3 V84.3 V94.3	105 153 61.5 141 203	212 212 380 380 380	360 360 530 530 530	0.850 0.850 1.52 1.52 1.52	1.32 1.32 1.95 1.95 1.95
Solar	Saturn Centaur Centaur "H" Taurus Mars T12000 Mars T14000	1	99 130 105 114 178 199	150 179 160 168 267	0.397 0.521 0.421 0.457 0.714 0.798	0.551 0.658 0.588 0.618 0.981
Westinghouse	W261B11/12 W501D5	52.3 119	220 190	355 250	0.882 0.762	1.31 0.919

300 - 20 June 1996

Gas Turbines

303 NOX CONTROL SYSTEMS FOR GAS TURBINES

The main methods available for the control of NOx emissions from gas turbines include diluent injection, selective catalytic reduction, and low NOx burners. NOx control systems can be categorized by being a "front end" control or a "back end" control. A front end control is an attempt to control NOx emissions by preventing them from forming during combustion. A back end NOx control is an attempt to convert NOx emissions (NO and NO₂) back to N₂, the natural form of nitrogen in the atmosphere. The amount of NOx emissions produced is highly dependent on the fuel, the ambient conditions, the design of the combustor, and the percentage of the rated full power output that the engine is operating.

Front or Back End Control

303.1 DILUENT INJECTION

Diluent injection, also known as wet controls, water injection, or steam injection, is a popular method used to decrease NOx emissions. It involves injecting water or steam into the combustor of a gas turbine in order to quench the flame. This lowers the combustion zone temperature inside the combustor. As stated earlier, the formation of NOx compounds is a function of the temperature inside the combustion chamber and lower combustion temperatures will produce less NOx. The temperature of combustion is the main factor affecting NOx formation.

Older gas turbines primarily made use of water injection, but today's modern gas turbines mostly use steam injection. Other factors such as the availability and cost of steam, impacts on maintenance and performance, and the availability of water or steam injection nozzles help determine the type of injection.

There are several conflicting factors that must be dealt with during diluent injection. In today's stationary gas turbines it is paramount that the engine runs with the highest efficiency possible. The lower the operating efficiency of a gas turbine the less cost effective it will be. Manufacturers have been designing gas turbines with higher firing temperatures to maximize the thermodynamic efficiency and therefore get the most work output for the least cost. The higher the turbine inlet temperature is the higher the thermodynamic efficiency. Unfortunately, higher firing temperatures create more NOx compounds. With increased NOx emissions, more diluent injection is required. When diluent

EMISSION CONTROL

Pressure Oscillations

Carbon Monoxide Increase injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. The flame temperature will continue to decrease and the flame stability will decrease as diluent injection is increased, but the NOx emissions will decrease. If the injection of steam or water in diluent injection is continually increased it will eventually extinguish the flame. Unfortunately, carbon monoxide emissions increase with higher diluent injection rates. Carbon monoxide emissions also generally indicate how well the combustion process is running. Less carbon monoxide emissions mean better, more efficient combustion. Figure 303.1 illustrates how carbon monoxide emissions increase as the ratio between water and fuel is increased. The figure also shows how emissions of unburned hydrocarbons increase with more water injection. The cooling effect of water injection is the cause of the increased CO and unburned hydrocarbon emissions.

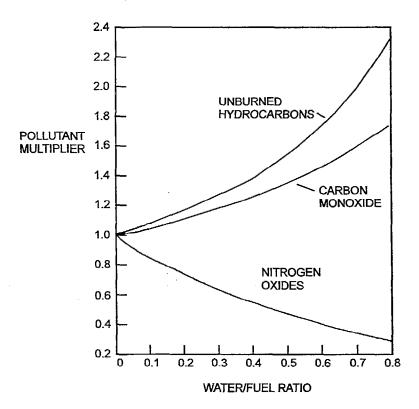


Figure 303.1 NOx, CO, and Unburned Hydrocarbons vs. Water Injection

The main factor affecting the performance of diluent injection is the ratio of water to fuel. The rate of water or steam injection is very important since it must be high enough to meet NOx emission regulatory limits, but the rate must be low enough so that turbine efficiency can be maximized and CO emissions are not too high. As water injection is increased the thermal efficiency decreases (Fig. 303.2). Water or steam injection has a benefit on the output work of a gas turbine because the injection of steam or water increases the mass flow rate through the turbine. As shown in Figure 303.2, the power output increases substantially with an increase in the water to fuel ratio.

Besides the water to fuel ratio, the geometry of the combustor, the design of the injection nozzles and the nitrogen content of the fuel can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture of water and fuel is created. Inefficient mixing of water and fuel will create hot spots in the combustor resulting in higher NOx emissions. Diluent injection only controls thermal NOx. Therefore, if the

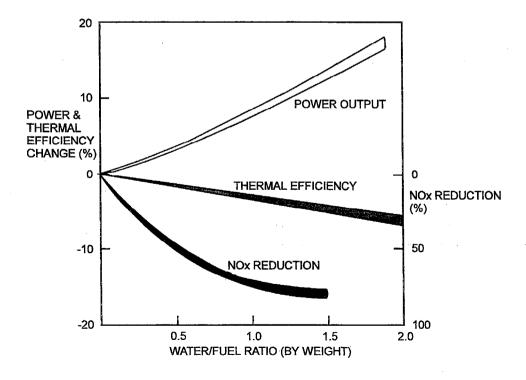


Figure 303.2 Effect of Water/fuel Ratio on NOx, Thermal Efficiency and Power Output

EMISSION CONTROL

Steam/Water Injection Comparison nitrogen content of a fuel is higher, the NOx emissions will be higher.¹⁷ This is why NOx emissions from using distillate oil fuel are still higher than natural gas even when diluent injection is conducted.

Newer gas turbines usually use steam injection even though water injection is usually more effective in terms of NOx reduction. Steam injection is usually a better alternative since it does not increase the heat rate as much as water; carbon monoxide emissions are increased a smaller amount, pressure oscillations are less severe and maintenance is reduced. When water injection is used, more energy is lost from the gas turbine since energy in the stream flowing through the turbine is used to vaporize the water. On the other hand, more steam (in terms of water to fuel ratio) is required than water to attain a given reduction in NOx because water behaves as a better heat sink. Steam injection is especially good for combined cycle gas turbines since the steam can come from the boiler section of the gas turbine and an additional boiler is not needed. The choice between using steam or water injection is highly dependent upon the availability of steam and economic considerations.

303.1.1 Water Treatment for Diluent Injection

A negative attribute of water or steam injection is that the water or steam must be very pure before injection into the turbine. Any contaminants in the water or steam will cause a buildup of deposits on the turbine blades and other equipment. Deposits on the turbine will reduce its efficiency, increase down time from maintenance, and in severe cases lead to failure of the equipment. The water treatment equipment between different plants can be very extensive, and the equipment will vary between different plants depending on the cleanliness of the source of water. Some of the equipment may include sand filters, gravel filters, membrane filters, chlorination units, reverse osmosis units, and ion exchange units. The water must be filtered free of floating matter. Chlorine is added to kill organisms, especially if the water is not from a municipality, and then removed. Dissolved minerals in the water must also be removed. By the time the water has been run through the treatment system, it is much purer than tap water. Many gas turbine power plants have labs to test their water at different points in their system to make sure the water quality stays high. Below an example of water quality requirements is illustrated:18

- -Total amount of metals (sodium, potassium, lead, vanadium, lithium etc. less than 0.1 ppm)
- -Total dissolved and nondissolved solids less than 5 ppm
- -Total suspended solids less than 10 mg/gal
- -Maximum size of solids less than 20 μ m

303.1.2 Examples of Diluent Injection Performance

When water injection is performed, the fuel flow rate is increased to keep the turbine inlet temperature at the rated setting. For example, for one gas turbine at a water/fuel ratio of 0.8 approximately 8.9% more fuel is required to maintain the turbine inlet temperature. In addition, there will be about a 6% increase in power output, but a 2 to 3% net increase (thermal loss) in heat rate. The increased fuel use is a result of the drop in thermal efficiency. On the other hand, at a ratio of water to fuel of one (equivalent amount of fuel and water being injected) on a weight basis, the drop in peak stoichiometric temperature reduces NOx emissions by 70 to 80% depending on the initial NOx level. In general, depending on the percent NOx reduction required, a water to fuel ratio between 0.6 and 1 on a weight basis is needed to reduce NOx emissions to 40 to 50 ppm for a natural gas fired gas turbine.

In order to reduce NOx emissions to 75 ppmvd for a typical simple cycle gas turbine burning oil, using water injection with a water rate half of the fuel flow rate, the heat rate will be increased 1.8%. The output work will rise about 3%. A typical gas turbine burning natural gas will require a water injection rate equal to the fuel flow rate to meet NOx emissions of 42 ppmvd.²¹ Carbon monoxide emissions from the gas turbine burning natural gas will be higher than the gas turbine burning oil from the higher water rate. Wear and tear will be higher from pressure oscillations, but output work will increase for the gas turbine burning natural gas.

Tables 303.1 and 303.2 show data from common gas turbine manufacturers with guaranteed NOx reductions attained with different water to fuel ratios.²² The data shows that for natural gas fuel, water to fuel ratios range from 0.33 to 2.48 and for distillate oil fuel, water to fuel ratios range from 0.46 to 2.28. These water to fuel ratios were used to attain NOx levels of 25 to 75 ppmv and 42 to 110 ppmv for natural gas and distillate oil respectively.

Manufacturer	Model No.	NOx, ppmv reduction	at 15% C	Water to fuel ratio (lb water to lb fuel)		
		No control	Water	Steam	Water	Steam
Asea Brown Boveri	GT8 GT10 GT11N GT35	430 150 390 300	25/94 25/83 25/94 42/86	29/93 42/72 25/94 60/80	1.86 0.93 1.76 1.00	2.48 1.07 2.47 1.20
General Electric	LM1600 LM2500 LM5000 LM6000 MS5001P MS6001B MS7001E MS7001F MS9001E MS9001F	133 174 185 220 142 148 154 210 161 210	42/68 42/76 42/77 42/81 42/70 42/72 42/73 42/80 42/74 42/86	25/81 25/86 25/87 25/89 42/70 42/72 42/73 42/80 42/74 42/80	0.61 0.73 0.63 0.68 0.72 0.77 0.81 0.79 0.78	1.49 1.46 1.67 1.67 1.08 1.16 1.22 1.34 1.18
GM/Allison	501-KB5 501-KC5 501-KH 570-K 571-K	155 174 155 101	42/73 42/76 42/73 42/58 42/58	42/73 25/84 	0.8 0.8	1.53
Siemens	V84.2 V94.2 V64.3 V84.3 V94.3	212 212 380 380 380	42/80 55/74 75/80 75/80 75/80	55/74 55/74 75/80 75/80 75/80	2.0 1.6 1.6 1.6 1.6	2.0 1.6 1.4 1.4 1.4
Solar	Saturn T-1500 Cent. T-4500 Centaur "H" Taurus Mars T12000 Mars T14000	99 130 105 114 178 199	42/58 42/68 42/60 42/63 42/76 42/79		0.33 0.61 0.70 0.79 0.91 1.14	
Westinghouse	W251B11/12 W501D5	220 190	42/81 25/87	25/89 25/87	1.0 1.6	1.8 1.6

300 - 26 June 1996

,	Table 303.2 M Water and Ste					
Manufacturer	Model No.	NOx, ppmv reduction	at 15% O	Water to fuel ratio (lb water to lb fuel)		
		No control	Water	Steam	Water	Steam
Asea Brown Boveri	GT8 GT10 GT11 N GT35	680 200 560 360	42/94 42/79 42/88 42/88	60/91 42/79 42/93 60/83	1.62 0.75 1.50 1.00	2.15 1.25 2.28 1.20
General Electric	LM1600 LM2500 LM5000 LM6000 MS5001P MS6001B MS7001E MS7001F MS9001E MS9001F	237 345 364 417 211 267 228 353 241 353	42/82 42/88 42/88 42/90 65/69 65/76 65/72 65/82 65/82	75/70 75/78 110/70 110/74 65/69 65/76 65/72 65/77 65/72	0.99 0.79 0.73 0.67 0.72 0.65 	 1.06 1.20 1.19 1.35 1.16
GM/Allison	501-KB5 501-KC5 501-KH 570-K 571-K	231 231 182 182	56/76 56/76 65/64 65/64	 50/78 		
Siemens	V84.2 V94.2 V64.3 V84.3 V94.3	360 360 530 530 530	42/88 42/88 75/86 75/86 75/86	55/85 55/85 75/86 75/86 75/86	1.4 1.4 1.2 1.2 1.2	2.0 1.6 1.4 1.4
Solar	Saturn T-1500 Cent. T-4500 Centaur "H" Taurus Mars T12000 Mars T14000	150 179 160 168 267	60/60 60/66 60/63 60/64 60/78 60/		0.46 0.60 0.72 0.96 1.00	
Westinghouse	W251B11/12 W501D5	355 250	65/82 42/83	42/88 42/83	1.0 1.0	1.8 1.6

June 1996

EMISSION CONTROL

Increased Maintenance

At higher diluent injection rates more frequent maintenance is required for gas turbines. In a Frame 6 gas turbine, for example, the first inspection of the gas turbine is required after 8000 hours of service when it is operating with steam injection with natural gas fuel to meet NOx emissions of 42 ppmv. When the Frame 6 is operated at higher steam injection rates to reach 25 ppmv with the natural gas, the first inspection is required after only 3500 hours of service.²³ Twice as much steam injection is required to meet 25 ppmv NOx emissions.

Gas turbine combustors that use more than one fuel nozzle per combustor can are able to operate with reduced dynamic pressure oscillations. An MS7001EA gas turbine with quiet combustors, for example, uses six fuel nozzles per combustor, has much lower dynamic pressure oscillations, and can get down to 25 ppmv of NOx without significant deterioration of equipment. While operating with steam injection at this emission level, the heat rate decreases 4% and the output work increases 6%.

303.1.3 Water-In-Oil Emulsion Injection

Water-in-oil emulsion injection is a method to reduce NOx emissions in oil-fired gas turbines by emulsifying water in fuel oil before it is injected into the combustor. This system reduces NOx by the same principles of water or steam injection, but with greater emission reduction. The injected oil-water emulsion is 20 to 50% water and it is finely dispersed and chemically stabilized throughout the oil phase. In addition to the metering and instrumentation equipment that a steam or water injection system has, a water-in-oil emulsion system will have mechanical emulsification equipment and chemical stabilizer equipment, but the system can use the existing oil fuel injection system. Steam and water injection are conducted with separate manifolds and nozzles.

303.2 SELECTIVE CATALYTIC REDUCTION (SCR)

Selective Catalytic Reduction is a back-end method of controlling NOx emissions that was first patented by a U.S. company in 1959 and further developed by Japanese and German manufacturers in the 1970s. It was originally developed for the control of NOx emissions from coal fired boilers in power plants. Using SCR can reduce NOx emissions by over 90%.

Gas Turbines

Selective catalytic reduction was first used to control NOx emissions from gas turbines in 1980 at the Kawasaki Plant of the Japanese National Railway in Japan. The first combined cycle power plant that used selective catalytic reduction was Tokyo Electric's 2000 MW Futtsu Power Station.²⁴ Since that time the use of selective catalytic reduction has become a common feature of gas turbine cogeneration and combined cycle systems in the U.S. Tens of thousands of megawatts are produced by coal fired power plants with SCR, now in operation in Europe. SCR is used to control NOx emissions from over 200 major NOx sources in the United States, and another 500 world wide.

1st Combined Cycle SCR

The selective catalytic reduction process basically works by using ammonia (NH_3) as a reagent, injecting it into the flue gas (exhaust) of the gas turbine, plus the use of a catalyst. The ammonia and NOx emissions react in the presence of the catalyst to form nitrogen (N_2) and water. Atmospheric nitrogen is usually in its diatomic form of N_2 and the water is non-polluting. The ammonia is injected into the process with air or steam. Oxygen is also required for the chemical reactions for SCR. The primary chemical reactions that occur are shown below.²⁵

SCR Reactions

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

Water or steam injection is often performed in a SCR system. As of 1993 there was only one gas turbine that used SCR as its only control. In some systems, low NOx combustors will be used with SCR. Water or steam injection typically reduces NOx emissions below 42 ppm, and then selective catalytic reduction reduces NOx to 10 ppm or less.

303.2.1 SCR Catalysts

The heart of a selective catalytic reduction system is the catalyst. The reaction converting NOx to nitrogen and water occurs on the surface of the catalyst. NOx compounds must come into contact with the catalyst in order to be converted. Older catalysts were in the form of small pellets. Today, catalysts are made in the form of parallel plates or honeycomb structures. The catalyst, in

EMISSION CONTROL

the form of rectangular modules, is installed into the heat recovery steam generator portion of the gas turbine downstream of the superheater. The modules are stacked together and form a single large catalyst.

Catalyst Pitch

In the honeycomb type of catalyst, the size of the openings in the catalyst is an important parameter. This parameter is called the pitch and it is gauged by the center to center distance between the adjacent openings in the catalyst. The smaller the pitch is, the larger the catalyst surface area will be. The pitch of catalyst used on gas turbines burning natural gas is generally 0.10 inches. The surface area of the catalyst is maximized, since compounds must come into contact with it to convert NOx to nitrogen. On the other hand, the smaller the openings in the catalyst are, the more prone the catalyst is to pluggage from contaminants. It is very important that the flue gas is distributed to the openings in the catalyst evenly. This is usually accomplished by flow straighteners, a dummy layer of catalyst and other devices.

Residence Time

The residence time of flue gases in the catalyst must be long enough for NOx compounds to be converted to nitrogen. As with the three T's of combustion (time, temperature, and turbulence) a longer time in the catalyst is better for NOx removal. The residence time is the volume of the catalyst "reactor" (i.e. ft³) divided by the volume flow rate (i.e. ft³/sec). The inverse of the residence time is the space velocity. For efficient NOx removal, the space velocity is usually about 30,000 per hour.

There are two ways in which the catalyst is built. A homogenous mixture containing the catalyst materials may be extruded into the catalyst shape. The second way to make the catalyst is to "wash-coat" the catalyst substrate with the catalyst material. The catalyst material then bonds to the substrate.²⁷ In the extruded catalyst design, a packing material, such as a high temperature ceramic wool, is put between the layers of catalyst modules.

Typical Catalyst Materials

Over 80% of the plants in the United States use "metal based" catalysts for selective catalytic reduction. The most common ones are vanadium pentoxide (V_2O_5) , titanium dioxide (TiO_2) , tungsten trioxide (WO_3) , aluminum oxide (Al_2O_3) and other noble metals. Most metal-based catalysts are often applied to the catalyst substrate as a wash-coat and vanadium pentoxide is one of the most common metal-based catalysts. Aluminum oxide or titanium dioxide catalysts are the two most common ingredients used for a catalyst made with the "wash-coat" method. Aluminum oxide was the main catalyst material used in older

Gas Turbines

selective catalytic reduction systems. Tungsten trioxide is not used as much as vanadium pentoxide and titanium dioxide. The titanium dioxide catalyst has a larger operating temperature range than aluminum oxide, but about 1/5 the area of aluminum oxide for the reaction.

New, better performing catalysts are still being developed. Newer catalysts and fabrication methods are yielding catalysts with larger temperature operating ranges and increased resistance to erosion, poisoning and blinding.²⁸ Zeolites are a class of catalyst that are making their way into SCR systems. Zeolite catalysts contain lower amounts of metals, which decreases potential contamination of soil and groundwater when the catalyst is disposed of. Aluminum silicates, a type of zeolite, can operate with temperatures up to 1100°F, which is about 300°F higher than many metal catalysts. The use of zeolite catalyst could eventually reduce the cost of SCR systems, increase the reactivity of the catalyst, and reduce emissions of ammonia (ammonia slip). Unlike base metal catalysts, zeolite catalysts usually form the structure and the active surface of the catalyst.

Iron oxides are another class of catalyst that has been tested in Germany. Iron oxide catalysts can operate at relatively high temperatures, but the catalyst requires a large volume. Activated carbon, which has been used to control volatile organic compounds for many years, is a new type of catalyst that has been commercially demonstrated in Germany and Japan.²⁹ Another new control technology that manufacturers are working on is the SOx-NOx-ROx-Box (SNRB). The SNRB will combine selective catalytic reduction with dry flue gas desulfurization and the SNOX process, which combines SCR with sulfur dioxide oxidation to produce salable sulfuric acid. This system has been demonstrated on coal fired utility boilers.

Operating experience illustrates that the selective catalytic reduction catalyst will usually last 8 to 10 years for systems using natural gas and 4 to 6 years for systems using distillate oil. Most manufacturers of the catalyst give at least five year warranties on them. Over time the effectiveness of the catalyst declines. The eventual replacement of catalyst is expensive.

Catalyst Disposal

The catalyst materials contain heavy metal oxides which are hazardous to human health. Vanadium pentoxide, for example, is on the Environmental Protection Agency's list of Extremely Hazardous Substances. In California, spent catalyst

Newer Catalysts

Zeolites

Iron Oxide

SNRB/SNOX

EMISSION CONTROL

Catalyst Recycling

from SCR is considered to be hazardous waste and the volume of wastes from SCR are large. The disposal of catalyst is expensive, but some catalyst manufacturers provide for disposal and/or recycling of the catalyst. In some cases spent catalyst can be used for other operations. In Japan, for example, titanium from titanium dioxide spent catalyst is used for paint pigment. An advantage of precious metal catalysts is that they do not produce as much hazardous waste, and they have a salvage value at the end of their useful life, but initial cost is higher.

Catalyst Masking and Poisoning

Particulates, ammonium salts, and other substances can deposit on the surface of the catalyst and inhibit catalyst activity by forming a barrier between the exhaust gas and the catalyst. Masking agents can usually be removed by vacuuming, soot blowing or by using steam. Over 90% of the catalyst activity can be regained by removing masking agents. Poisoning agents chemically react with the catalyst and render it inactive. Catalyst poisoning is permanent and the effects of it can only be improved by replacing the catalyst.

The source of making and poisoning agents is usually the fuel and natural gas is usually free of masking and poisoning agents. On the other hand, some digester gas and refinery gas fuels contain contaminants. Field gases are analyzed for the presence of arsenic, iron, and silica. For distillate oils, particulates and heavy metals are potentially damaging to the catalyst. The leading edge of the catalyst is also subject to erosion, especially if there is any dust or particulate present. Dummy layers of catalyst can be used to reduce erosion.

303.2.2 Temperature Control for SCR

The chemical reactions that take place in selective catalytic reduction occur over a small temperature range. For a selective catalytic reduction system operating with a vanadium pentoxide catalyst, the allowable temperature range is generally between 600 to 800°F (Fig. 303.3). It is important to keep the temperature of the reaction in this temperature range because if it drops below 600°F, the reaction efficiency becomes too low and excessive amounts of ammonia will be released out of the stack. If the reaction temperature gets too high the catalyst may start to decompose. Furthermore, ammonia will begin to decompose at temperatures above 850°F.

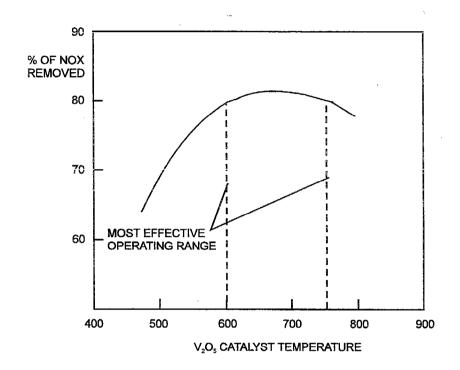


Figure 303.3 % NOx Removed vs. Vanadium Pentoxide Catalyst Temperature

A heat recovery steam generator (HRSG) containing the catalyst is required with SCR so that the flue gas can be cooled to the appropriate temperature when it reaches the SCR catalyst (Fig. 207.1). When exhaust gases exit a gas turbine the temperature of the gases is usually over 1000°F, which can be too high for selective catalytic reduction, but some high temperature zeolite catalyst, which can operate at temperatures up to 1100°F, have become available.³⁰

It is usually impractical to add a boiler section or HRSG to an existing simple cycle gas turbine in order to add SCR. An HRSG is a very large integral part of a gas turbine and it is much larger than the gas turbine. They are typically over four stories high. The catalyst bed alone for a Frame 7, 83 MW gas turbine, for example, weighs 110 tons and has a volume of 175 cubic meters.³¹ It is not practical to move the SCR catalyst to the best temperature zone, so the unit must be designed carefully.

EMISSION CONTROL

After hot combustion gases leave the turbine, more fuel may be injected and burned at the duct burner to add more heat energy to the flue gases (Fig. 207.1.). The hot gases then flow through the superheat section where energy transfers form the exhaust gases to make superheated steam. The gases then flow through the carbon monoxide (CO) catalyst which removes carbon monoxide. More energy is extracted from the flue gas, producing high pressure steam and cooling the gases to the appropriate temperature before flowing through the NOx catalyst of the SCR. An economizer or low pressure evaporator, which consists of more boiler tubes, may be located after the SCR to extract remaining usable energy from flue gases, producing low pressure steam. Temperature variations in the SCR section occur under different load conditions. This can make the locating of the catalyst more difficult.

303.2.3 Effects of Sulfur Compounds with SCR

Systems that use selective catalytic reduction to control NOx emissions and use a fuel containing sulfur may have several problems. After the sulfur in a fuel burns in the combustor, forming sulfur dioxide (SO₂), the SCR catalyst may oxidize the sulfur dioxide to sulfur trioxide (SO₃). Metal-based catalysts convert up to 5% of sulfur dioxide to sulfur trioxide and carbon monoxide catalysts will also oxidize up to 50% of sulfur compounds into sulfur trioxide.³² The sulfur trioxide can then react with the ammonia present in the flue gas, forming ammonium salts such as ammonium bisulfate (NH₄HSO₄) and ammonium sulfate [(NH₄)₃SO₄].

Ammonium Salts

Effects of Ammonium Salts Ammonium bisulfate can rapidly corrode the boiler tubes in the heat recovery steam generator. Ammonium bisulfate is also a sticky substance, causing the fouling and plugging of boiler tubes, catalyst beds and other equipment. Ammonium sulfate is not corrosive but it will coat, foul and plug equipment. The coating of ammonium salts on the tubes and walls of the HRSG reduces the heat transfer from the hot flue gas to the steam and boiler feed water, reducing the power output of the steam turbine. A buildup of material leads to higher pressure drops in the HRSG and increased back pressure on the turbine. Ammonium bisulfate and ammonium sulfate are also particulate emissions once they exit the stack of the gas turbine. Ammonium salts can be periodically removed from the HRSG by water washing. The removal of ammonium salts helps reduce the rate of corrosion and improve efficiency, but the gas turbine must be shut down for the cleaning, leading to increased costs from down time.

Gas Turbines

The most effective ways to eliminate problems with sulfur compounds in SCR is to use fuels with no sulfur in them or to limit ammonia slip. Natural gas usually has little or no sulfur, but distillate oils usually have some sulfur in them. Some types of natural gas contain hydrogen sulfide which will contribute to ammonium salt formation. Even the lowest sulfur distillate oils will have some ammonium salt formation from the SCR system.³³

There are catalysts available for SCR that help prevent the oxidation of sulfur dioxide to sulfur trioxide. These catalysts can be used when a distillate fuel is being used to help prevent the formation of ammonium salts. Catalysts that contain tungsten trioxide (WO₃) help reduce the formation of sulfur trioxide. Silica based catalysts, which contain titanium dioxide (TiO₂) deposited within silica impregnated with vanadium pentoxide (V₂O₅), perform with a 50% increase in NOx conversion and will reduce the formation of sulfur trioxide.³⁴ This catalyst can also operate in temperatures which are above ammonium bisulfate formation temperature. Some catalysts that are designed to limit ammonium salt formation are not as efficient at NOx removal; therefore a larger catalyst volume is required. Zeolite catalysts are good at preventing ammonium salt formation since they convert less than 1% of sulfur dioxide to sulfur trioxide.³⁵ Problems with sulfur trioxide can occur when the sulfur content of the fuel increases. Replacing the catalyst with a newer sulfur trioxide resistant type may not be economical.

There are other methods of dealing with sulfur trioxide and the formation of ammonium salts. The inlet temperature of the flue gases entering the SCR catalyst can be raised above the ammonium bisulfate formation temperature. Ammonium salts form mostly in the lower temperature regions of the HRSG. Unfortunately, this could result in a decrease in energy output, because some economizer tubes may have to be removed or a bypass around the economizer may have to be constructed. Energy is lost because heat energy that was transferred to the economizer to make steam would instead be left to keep the flue gases hotter and flow out the stack.

Another method of controlling sulfur trioxide formation is to reduce the ammonia slip as much as possible. It should be possible to reduce ammonia slip to between 5 and 3 ppm and possibly even lower.

Catalysts to Prevent SO, Formation

EMISSION CONTROL

303.2.4 Ammonia Use

SARA

Ammonia is necessary for the chemical reactions in SCR to work. Unfortunately, ammonia is also a hazardous substance. Ammonia is on the Environmental Protection Agency's list of extremely hazardous substances under Title III, Section 302 of the Superfund Amendments and Reauthorization Act of 1986 (SARA). Ammonia is immediately dangerous to life and health (IDLH) at only 500 ppm. It has a time weighted average (TWA) exposure limit (the maximum allowable exposure limit in a 10 hour day in a 40 hour week) of 25 ppm. Ammonia has a pungent, suffocating odor. Exposure to ammonia causes eye, nose, and throat irritation and it will burn the skin.

Molar Ratio

Ammonia is released from an SCR system because excess ammonia is required for efficient conversion of NOx to nitrogen. Excess ammonia is required because of imperfect distribution of the chemical. In theory, if the ammonia could be perfectly distributed so all the reactants could come into contact, no ammonia would be released, but in the real world this is not possible. This is also analogous to the necessity for excess air required for combustion. Excess air is required since all the oxygen molecules can't find all the fuel molecules to react with during the short period of time of combustion due to imperfect mixing of fuel and air. The molar ratio of nitrogen oxide (NO) to ammonia in the SCR reaction is 1.0 (i.e. 1 ft³ of ammonia is required to convert 1 ft³ of NOx), and the molar ratio of ammonia to nitrogen dioxide (NO₂) is two. Over 80% of the NOx compounds in the exhaust are nitrogen oxide, so the SCR system is usually run with a ratio of ammonia to NOx around 1.0. Further increase of the ratio will reduce NOx emissions, but emissions of ammonia will increase. Once the stoichiometric ratio of ammonia to NOx reaches about 0.85, the efficiency of the conversion of NOx due to the molar ratio begins plateau somewhat. In an SCR unit it is critical that the ammonia is injected and thoroughly distributed throughout the flue gas stream.

Ammonia Slip

The unavoidable release of ammonia is called ammonia slip. The ammonia slip in a typical new SCR system may be 10 to 20 ppm.³⁶ Some of the most efficient systems have reached NOx removal efficiencies of 90% with a slip below 5 ppm.³⁷ In general, the more ammonia that is used the higher the ammonia slip, but the conversion of NOx to nitrogen may increase. As a catalyst ages the ammonia slip increases. Some SCR catalysts act to react with unreacted ammonia to reduce ammonia slip.

Gas Turbines

The storage of ammonia is usually considered to be a greater potential hazard than the ammonia slip from the stack. Permitted levels of ammonia slip are far below the odor and health hazard thresholds of the chemical. Since ammonia is water soluble, it doesn't remain very long in the atmosphere.

Ammonia for SCR is stored in a tank and a relatively large amount of storage is required. An accidental release from storage could pose problems to communities surrounding the plant. Aqueous and anhydrous ammonia are the two types of ammonia used for ammonia injection. The aqueous form is favored in that the stored ammonia concentration can be limited and volatilization rate is reduced, so it is safer. The aqueous form is used in more heavily populated areas. Most companies use aqueous ammonia with a concentration ranging between 30 to 40%. Nationwide, the anhydrous form of ammonia is still used more often. When there is an accidental release of aqueous ammonia with a lower concentration, the ammonia will be released into the air at a slower rate and it will be dispersed faster.

Aqueous & Anhydrous Ammonia

303.2.5 Typical Emissions from SCR

Table 303.3 illustrates emissions of NOx and ammonia from some U.S. gas turbine plants using SCR and natural gas fuel.³⁸ The table shows the SCR operating temperature, molar ratio, NOx emissions before and after the SCR operation, the percent reduction of NOx and the ammonia slip. The one plant with an ammonia slip of 35 ppm operates without diluent injection. With diluent injection on systems burning natural gas, NOx emissions can usually be brought down between 25 to 42 ppmv. Many SCR systems have a NOx removal efficiency between 80 to 90%; therefore, theoretically, emissions from a system with diluent injection and SCR would be between 2.5 and 4.2 ppmv. As can be seen from Table 303.3, in actual practice emissions of NOx are usually higher than this amount.

303.2.6 SCR Cost

Although the capital cost and operation cost of a SCR system are high, SCR can be cost effective compared to other NOx control methods. The Environmental Protection Agency considers cost in determining if a control technology is

EMISSION CONTROL

Table 303.3 Typical NOx Reductions and Ammonia Slip from Various Gas Turbine Plants									
Make	Model	Power (MW)	Temp. of SCR (deg. F)	Max. Molar Ratio (NH3/NOx)	NOx Emissions (ppmv) at 15% O2			NH3 Slip (ppmv) at 15%	
					SCR in	SCR out	% Reduction	O2	
GE	LM2500	22	730	1.0	50	9.0	82	10	
GE	MS5001	18	645	1.0	45	4.5	90	2	
GE	LM2500	22	685	1.1	37	8.9	76	20	
ABB	Type 8	44	760	1.2	27	4.0	85	9	
GE	LM2500	22	680	1.0	60	12.6	79	7	
GE	MS7001	80	630	1.0	28	8.4	70	4.1	
GE	LM2500	22	625	0.9	68	13.6	80	1	
Allison	501-KB	3.5	650	1.1	25	1.0	96	10	
Solar	Mars	8.5	580	1.6	130	18.2	86	35	
GE	LM2500	22	750	1.0	37	14.8	60	11	
GE	MS7001	80	754	1.0	40	6.0	85	2	
GE	MS6001	37	650	1.0	47	8.9	81	4	
GE	MS6001	37	700		33	3.3	90	8	

effective. A control must be cost effective in order to be a Reasonably Available Control Technology (RACT). In one EPA estimate, for example, NOx control was effective if it cost less than \$1,300 per ton.³⁹

SCR Cost

Besides the initial cost and operating cost, there is also a cost incurred by the damage to the environment from NOx emissions. Cost estimates from public utilities of damage from NOx are typically several thousand dollars per ton. The operation cost of an SCR system in a gas turbine are approximately \$1,000 per ton to \$2500 per ton.⁴⁰

Gas Turbines

303.3 SELECTIVE NONCATALYTIC REDUCTION (SNCR)

Selective noncatalytic reduction is a method used to control NOx emissions by injecting ammonia into the flue gas in order to convert the NOx to nitrogen. Urea or ammonium hydroxide can also be used and as with SCR, anhydrous or aqueous ammonia may be used in the operation. When urea is used it quickly dissociates to ammonia. The SNCR process is conducted at higher temperatures than SCR; selective noncatalytic reduction is conducted at temperatures between 1,700 and 1,900°F. At temperatures above 1,900°F, the ammonia begins to oxidize into NOx compounds at an excessive rate. This can result in an increase of NOx emissions in excess of the NOx originally in the flue gas by the following chemical reaction:

$$NH3 + O_2 \rightarrow NOx + H_2O$$

The chemical reaction that is desired to remove NOx is: $NOx + NH_3 \rightarrow N_2 + H_2O$

At temperatures below 1,700°F the rate of the chemical reactions converting NOx into nitrogen decline and the emissions of ammonia out of the stack rapidly increase. The process is very sensitive and a large amount of flow or temperature modeling may be required to perform injection at the right location in a furnace for the correct temperature window. SNCR is not used for gas turbines because the exhaust gases leaving the turbine are around 1,000°F, far below the temperature required for SNCR.

One problem with SNCR when urea injection is used is the formation of nitrous oxide (N_2O) , which is a greenhouse gas. As much as 5 to 40% of the nitrogen oxide (NO) in flue gas may be converted to nitrous oxide with urea injection. When aqueous ammonia injection is used the conversion of nitrogen oxide to nitrous oxide is less than 5%.

The operating temperature of SNCR can be reduced down to 1,300°F by injecting hydrogen into the process. The following reaction then occurs: $NOx + NH_3 + O_2 + H_2O + H_2 - N_2 + H_2O$.

SNCR Reaction

SNCR with Hydrogen

EMISSION CONTROL

303.4 LOW NOX COMBUSTORS

The design of a combustor is the single biggest factor that affects the quantity of NOx emissions. Thermal NOx is the type of NOx that is most prevalent and the temperature and residence time in a combustor have the greatest effect on thermal NOx formation. The amount of cooling air used in the combustor and the effectiveness of air and fuel mixing also affect NOx production. Combustion modifications can also help reduce the formation of NOx from fuel bound nitrogen.

The main modifications that can be made to reduce NOx formation include: operating with lean air/fuel ratios, reducing residence time, two stage rich lean combustion, and lean premixed combustion. These modification techniques can be applied singly, and some can be applied in conjunction.

Lean Combustion

Operating a combustor in a lean mode involves using an air/fuel mixture where there is more air relative to the amount of fuel. The excess of air during combustion cools the flame and less NOx is produced. Dilution air, which flows through the holes in the combustor liner, cools combustion gases and reduces thermal NOx. The leaner the air fuel mixture is, the less NOx will be produced, but carbon monoxide emissions will begin to increase and the flame in the combustor will begin to become unstable. Because of these problems, NOx reduction by using lean combustion alone has limitations.

Residence Time

The residence time of a combustor can be reduced by reducing its length. With a shorter length combustion gases pass through the combustor in a shorter period of time and NOx compounds have less time to form, so less NOx is produced. Dilution air can be added sooner in a shorter combustor, shortening the time that gases are exposed to high temperatures.

On the other hand, reducing the time for combustion to occur (time is one of the three T's of combustion) can increase carbon monoxide and hydrocarbon emissions. Reducing residence time gives less time for combustion to be complete. This problem can be counteracted by increasing turbulence in the combustor (turbulence is another one of the three T's of combustion). Combustors may be designed with air distribution ports, premixing chambers and other devices may be used to increase turbulence and increase mixing of the fuel and air.

Gas Turbines

Tests have shown that NOx emissions could be reduced by as much as 30% by lean combustion without an increase in CO emissions. In another test operating with a reduced residence time resulted in a 40% decrease in NOx emissions and 10 to 30 ppm increase in carbon monoxide emissions.⁴¹

303.4.1 Lean Premixed Combustors

Work toward development of low NOx combustors began in the early 1970's to meet NSPS and California regulations. The first successful gas turbine combustor to meet the NSPS NOx limit of 75 ppmvd at 15% $\rm O_2$ was tested in 1978 in a laboratory.⁴² The unit operated on a MS7000 gas turbine and was oil fired. The low NOx burner operated by mixing oil and air, partially vaporizing the liquid oil before combustion, but it could also operate on natural gas. The combustor was first operated and tested at Houston Lighting and Power in 1980. Development of low NOx combustors during the 1980's concentrated on those that operated on natural gas.

In a conventional combustor when the air and fuel are mixed small localized rich areas are created resulting in higher NOx compounds. This occurrence is minimized in lean premixed combustors premixing air and fuel in lean air-fuel mixtures before the air-fuel mixture reaches the combustion zone. Excess air in the air-fuel mixture acts as a heat sink, which helps lower temperatures and produce less NOx. In order to reach NOx levels below 50 ppm (at $15\% \, {\rm O_2}$) the lean flammability limit is approached. In order to operate with a stable flame and complete combustion, lean premixed burners use a pilot flame that operates on a small amount of air and fuel that is near stoichiometric. The pilot flame produces more NOx, but it keeps the primary combustion of the burner operating.

Figure 303.4 illustrates a lean premixed combustor design with the location of the pilot. Air and fuel are premixed with a very lean air fuel ratio and this mixture is delivered to the primary combustion zone where combustion is stabilized by the pilot flame. This combustor is equipped with swirl vanes to increase turbulence and improve mixing of the air and fuel. The secondary zone has holes in the liner to allow air flow for dilution of the combustion gases for NOx and temperature control. When the gas turbine runs below 50% load, only the pilot operates and the combustor works as a conventional combustor with

1st Lean Premix Combustor

Pilot Flame

EMISSION CONTROL

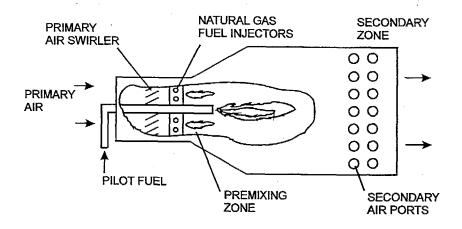


Figure 303.4 Lean Premix Combustor

higher NOx emissions. From 50% to 100% load the combustor operates in premixed mode, combustion occurs in the premix area and the pilot still operates.

Figure 303.5 illustrates another lean premixed burner design for an annular combustor. It generally applies the same principles of the original design. They are able to achieve a NOx limit of 25 ppmvd or less at 15% $\rm O_2$ when fired with natural gas with no steam or water injection. The burner has a two stage

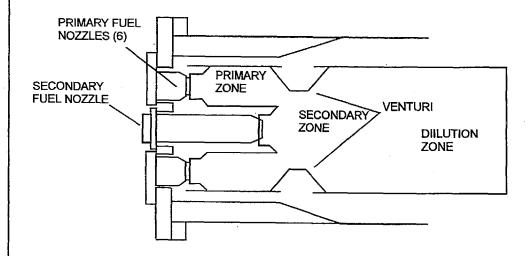


Figure 303.5 Annular Lean Premix Burner

premixed combustor and it is designed primarily to run on natural gas, but may also be oil fired with diluent injection. It also has six primary fuel nozzles and a secondary fuel nozzle.

Modes of Operation for the Lean Premix Burner Using Natural Gas

The four modes of operation for the lean premix burner operating on natural gas are: primary mode, lean-lean mode, secondary mode and premixed mode.

The lean premix burner operates in the primary mode for ignition, warm up of the gas turbine, acceleration and low loads up to 20% of the maximum load.⁴³ In the primary mode, fuel is introduced to only the primary nozzles and firing occurs in the primary stage (Fig. 303.6).

After maximum heat release is attained in the primary mode, fuel is also introduced to the secondary fuel nozzle and the burner enters the lean-lean mode of operation. Approximately 70% of the fuel is delivered to the primary stage and 30% is delivered to the secondary stage. The flame in the second stage

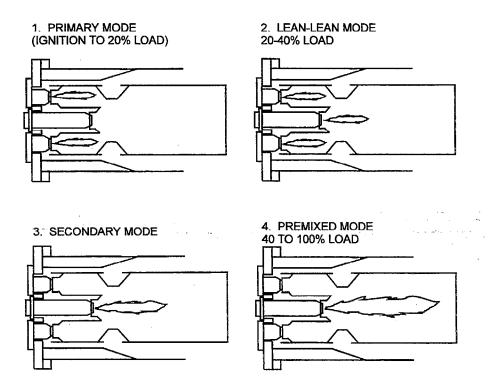


Figure 303.6 Lean Premix Burner Modes

EMISSION CONTROL

behaves as a subpilot and helps stabilize the flame. A flame burns in the primary and secondary stages in the lean-lean mode, with the combustion products from the primary stage mixing with the fuel and air from the second stage. The flame in the secondary stage is called a "diffusion flame" since the fuel and air leaving the secondary nozzle are diluted by the combustion products.

The lean premix combustor will stay in the lean-lean mode until the load on the gas turbine reaches approximately 40% of the maximum load. The combustor senses the end of the lean-lean mode from the air/fuel ratio. The air/fuel ratio for the end of the lean-lean mode is preset into the device. When the combustor goes into the secondary mode, the fuel to the primary nozzles is cut off and only the secondary burner operates. In the secondary mode, increases in the turbine load are temporarily halted. Once flame detectors sense that flame in the primary stage is totally extinguished, fuel is again introduced into the combustor by the primary fuel nozzles and the unit begins to operate in the premixed mode. The turbine load can then be increased up to 100% (most gas turbines are set to operate at full load). In premixed operation approximately 80% of the fuel is introduced into the combustor by the primary nozzles and the remaining 20% is delivered to the second stage. Air is also introduced in the primary stage, and this allows the fuel and air time to thoroughly mix and provide efficient combustion which occurs only in the secondary zone. When the dry low NOx burner operates in the premixed mode, emissions are at their minimum (Fig. 303.7).44

Venturi

The venturi in the dry lean premix burner prevents the flame in the secondary zone from flashing back to the primary zone when the combustor operates in the premixed mode. The venturi acts as a converging/diverging nozzle that accelerates the fuel and air. The venturi is designed so that it has a recirculation zone on its downstream side that helps stabilize the flame in the secondary zone. The air/fuel mixture in the second stage is very lean and little NOx is produced; the mixture is so lean that it would not burn efficiently and stably by itself. Fuel added in the second stage at the secondary nozzle helps act as a second pilot flame to stabilize the flame.

June 1996

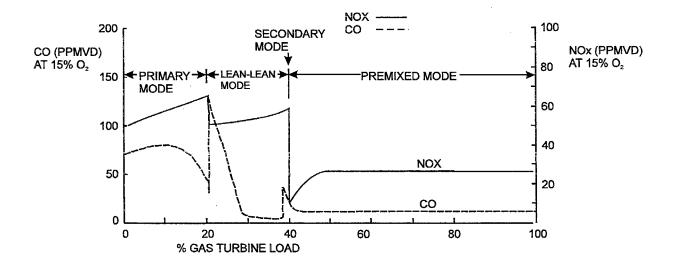


Figure 303.7 NOx and CO vs. Gas Turbine Load

The dry lean premix burner can also operate on distillate oil for fuel. The operation of the burner with distillate oil is similar to natural gas. With distillate oil the burner operates in the primary mode up to approximately 50% maximum load. The primary mode is used for start-up and part load operation. Over 50% load and up to full load the burner operates in the lean-lean mode.

Achievable NOx Reductions with Lean Premix Combustors

NOx reductions from combustor designs from various manufacturers vary widely. As of 1993 three manufacturers guaranteed their lean premix combustors could reach 25 ppmv, corrected to 15% O₂, operating on natural gas with no diluent injection. These manufacturers were also able to attain emissions below 10 ppmv at specific plants in the United States and Europe. ⁴⁵ These emissions were attained under ideal conditions at full load.

With distillate oil, emission levels down to 65 ppmv have been attained with lean premix combustors with diluent injection. Lower emission levels can be attained with a conventional combustor operating with water injection.

EMISSION CONTROL

303.5 STAGED COMBUSTOR

RQL Combustor

The staged combustor (also called the rich/quench/lean or RQL combustor) is a low NOx combustor that is currently being researched for use in civilian aircraft fleets and possible use for stationary engines. The staged combustor has three zones which include the rich burn zone, the quick quench zone and the lean zone (Fig.303.8). The rich burn zone burns rich as the name indicates. Incomplete combustion occurs in the rich burn zone resulting in relatively higher amounts of carbon monoxide and hydrogen. The carbon monoxide and hydrogen replace some of the oxygen normally available to create NOx compounds and behave as reducing agents for any NOx formed. This helps reduce NOx formation from fuel bound nitrogen by converting NOx compound to N₂, the normal form of atmospheric nitrogen. The incomplete combustion occurs at lower temperatures, so thermal NOx is also reduced.

Fuel is supplied to the combustor by an advanced air-blast fuel nozzle which consists of three coaxial swirled air passages and one fuel passage.⁴⁶ The passages are called the inner, outer, and dome respectively, from the center axis of the combustor outward. The fuel nozzle is located between the inner and outer passages.

Dilution Slots

In the quick quench zone are located a set of air dilution slots which are at a 45° angle. Air or even water is used to rapidly dilute and cool combustion products and a lean air/fuel mixture is created. The quick quench zone also has a short

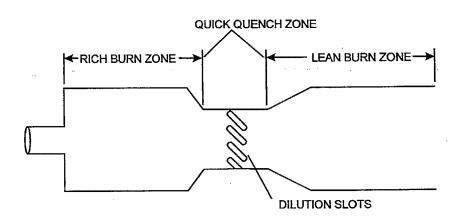


Figure 303.8 Staged Gas Turbine Combustor

Gas Turbines

residence time to minimize NOx formation. Lean combustion then occurs in the third section of the combustor. Since the lean combustion occurs at low temperatures, the formation of thermal NOx is minimized.

Tests of the staged combustor with diesel fuel have shown NOx reductions between 40 and 50%. At an equivalence ratio of 1.8 and quick quench air flow between 0.86 and 1.4 kg/sec, NOx emissions were reduced from 0.50 to 0.27 lbm/MMBtu. Increasing the fuel bound nitrogen content from 0.13 to 0.88% had little effect on NOx emissions at equivalence ratios between 1.3 and 1.4. Reductions in fuel bound nitrogen emissions were between 50 and 80%.⁴⁷

303.6 CATALYTIC COMBUSTION

Catalytic combustion involves using a catalyst bed to oxidize a lean air/fuel mixture within a combustor instead of burning with a flame as a blow torch in a conventional combustor. In a catalytic combustor the air/fuel mixture oxidizes at lower temperatures, producing less NOx.

Catalytic combustion is not a new technology. In the past it was never a reliable system because the catalyst would not last long enough to make the combustor economical. The catalyst would be exposed to high temperatures from the combustion occurring on the surface of the catalyst metal. Heat would be transferred to the gases flowing through the combustor from the hot catalyst. The catalyst would suffer from high thermal stress and thermal shock from the large changes in temperatures encountered between startup and full load. The durability of the catalyst was poor since it would become brittle and deteriorate in a short period of time.

One manufacturer currently has available a catalytic combustion system known as the XononTM flameless combustor that is currently demonstratable with NOx emissions below 3 ppm and carbon monoxide and unburned hydrocarbon emissions below 10 ppm with no other emission controls. This system will start undergoing official testing in a Kawasaki gas turbine in July of 1996 and will be commercially available for Kawasaki engines in 1997.

This new combustor employs a "chemical thermostat" that prevents the catalyst from getting too hot. It has a PdO/Pd catalyst that is very active at low temperatures, but it loses its activity at high temperatures. At lower

Flameless Combustion

PdO/Pd Catalyst

EMISSION CONTROL

temperatures it remains as PdO, but at higher temperatures it becomes Pd, which helps control the temperature. Furthermore the catalyst is in several stages and it is plated only one side of the catalyst. This also helps keep the temperature down and reduce NOx emissions.

This new combustor runs with an extremely lean air/fuel mixture that is too lean to form a flame as in a conventional combustor. In this manner it uses principles similar to lean premix combustors. Lean premix combustors have been able to operate with NOx emissions down to 25 ppm. NOx levels below 15 ppm are difficult to attain since, at the air/fuel ratio required to attain those emissions, the flame becomes unstable.

Preburner

The Xonon[™] combustor is equipped with a preburner which is used for start up and acceleration of the gas turbine. Conventional gas turbine combustors can work as the preburner for some engines. The preburner is usually only necessary for gas turbines with low pressure ratios below 10, because the temperature of the air exiting the compressor is not high enough for combustion in the catalytic combustor.

Data from the manufacturer of the XononTM systems shows that the new combustor will be economically competitive with other emission control systems for gas turbines (lean premix combustors, SCR and SCR and lean premix combined). Data shows that the capital costs of the catalytic combustor are competitive with other control technologies. The capital costs and operating costs of SCR are significantly higher than the XononTM system.

303.7 DUCT BURNER EMISSIONS

The effect of duct burners on the total NOx produced from a power plant varies with different systems, but duct burners produce relatively small amounts of NOx emissions. In some systems a duct burner can even reduce NOx emissions. The cause of the reduction of NOx is not completely understood, but it is believed to be caused by a reburning process. In the reburning process intermediate combustion products from the duct burner interact with NOx compounds from the gas turbine, forming nitrogen and oxygen. Table 303.4 shows NOx emissions from test runs from a system where reburning seems to occur. 47.1 Conditions that appear to increase the occurrence of reburning include: 48

Gas Turbines

	Table 303.4 Duct Burner Emissions										
Test	Load (MW)	Water fuel ratio	Duct burner operating c		Duct burner inlet emissions (NOx)		Duct burner outlet emissions (NOx)		(NOx) Change from duct burner		
			Heat input MMBtu/hr	Load (%)	lbm/ MMBtu	lbm/hr	lbm/ MMBtu	lbm/hr	lbm/ MMBtu	lbm/hr	
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7	
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1	
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2	
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9	
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2	
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5	
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0	
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0	

⁻The burner flame producing a high temperature in the fuel rich zone of the duct burner.

304 CARBON MONOXIDE EMISSION CONTROL

Carbon monoxide (CO) emissions from gas turbines are usually small, especially when compared to NOx emissions. Carbon monoxide is a result of partially burned fuel or incomplete combustion.

A catalyst is used to convert carbon monoxide to carbon dioxide (CO_2) by oxidizing the carbon monoxide molecules. The following reaction occurs at the catalyst:

$$2CO + O_2 \rightarrow 2CO_2$$

⁻Turbine exhaust gases having a sufficient residence time in the fuel rich zone,

⁻Fuel having little or no fuel bound nitrogen.

EMISSION CONTROL

The carbon monoxide catalyst is similar to the catalyst used for selective catalytic reduction. As with the SCR catalyst, the CO catalyst is designed to maximize surface area, since carbon monoxide molecules must come into contact with it to be converted to carbon dioxide. The CO catalyst is often made with a honeycomb structure or parallel plates. The active element that oxidizes the carbon monoxide is a precious metal such as platinum. The catalyst is often applied as a coating over the catalyst structure. In order to withstand the high temperatures downstream of the turbine the catalyst structure is made with a ceramic material. In some ways the CO catalyst is very similar to a catalytic converter on a car.

Pressure Drop

Most carbon monoxide catalysts operate between 700 and 1000°F and the efficiency of the oxidation of carbon monoxide is usually between 80 and 90%. The catalyst causes a pressure drop between 1 and 2 inches of water. As with the SCR catalyst, the CO catalyst is made of rectangular "box-like" modules. The structure of each module is typically made of steel.

The carbon monoxide catalyst is placed in the heat recovery steam generator so it will be in the correct temperature range. The catalyst is designed to operate at the high temperatures at the front end of the HRSG. The carbon monoxide catalyst is usually placed before the ammonia injection grid, because the carbon monoxide catalyst will not only oxidize CO, it will oxidize the ammonia into NOx compounds. This would lead to an increase in NOx emissions.

Some diesel engines or dual fuel power plants may have designs where the carbon monoxide catalyst is placed after the ammonia injection and SCR catalyst. In diesel engines, the NOx emissions are usually an order of magnitude higher than gas turbines. With the carbon monoxide catalyst downstream of the SCR system, the unit can be more compact and the ammonia injection system will be more simplified. Due to ammonia slip past the SCR catalyst, there will be a small increase in NOx emissions from the oxidation of ammonia, but overall there will still be a high NOx removal efficiency.

Carbon monoxide catalysts operate best with low sulfur diesel fuel or natural gas. As with the SCR catalyst, the CO catalyst can become fouled by sulfur compounds and other contaminants.

Gas Turbines

305 STACK SAMPLING

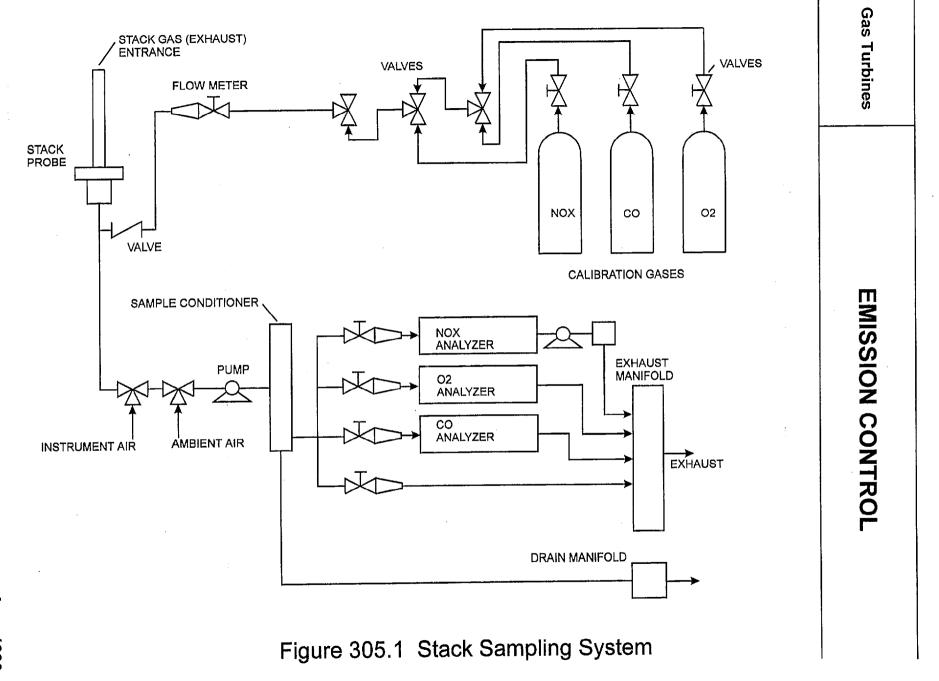
Gas turbines usually have automatic sampling systems or continuous emissions monitors. Figure 305.1 illustrates the major components of an automatic sampling system for a gas turbine. Emissions are initially drawn into the system through the probe which is mounted into the stack so it is exposed to the exhaust. A small pump is used to acquire a sample from the stack. The sample is conditioned by removing moisture and by raising or lowering the temperature to that which is best for the analyzers. After the exhaust passes through the analyzer it goes into an exhaust manifold and out to the atmosphere. The system is also equipped with calibration gases. Nitrogen oxides, carbon monoxide, and oxygen are the types of calibration gases that are usually used. When calibrations are performed, the valve to the desired calibration gas is opened, while no exhaust is allowed to flow through the probe. Since the concentration of the pollutant in the calibration gas is known, the operation of the analyzers can be checked. Valves also allow more than one calibration gas to be injected into the system at once.

306 AIRCRAFT EMISSIONS

As of the time of the printing of this manual, there were no regulations just for the control of emissions from aircraft engines. Any future control or regulations for aircraft emissions will probably be in the Federal EPA's jurisdiction, since aircraft often travel across state boundaries. Visible emissions are the most obvious emissions from aircraft, but with current regulations it is not possible to perform a visible emissions evaluation. Within the time required to perform a visible emissions evaluation an aircraft would be too far away from the observer and most likely out of sight. Commercial airliners produce varying amounts of smoke from the exhaust of the engines varying from hardly visible to relatively moderate, but some military aircraft, especially older ones and those with take-off water injection, can leave behind thick clouds of smoke. Research to reduce emissions from aircraft is being conducted.

The highest NOx emissions from aircraft occur during takeoff and climb. Emissions of unburned hydrocarbons and carbon monoxide from aircraft engines is highest during taxiing.

Visible Emissions



Gas Turbines

Once a plane has reached cruising speed and altitude, NOx emissions decrease to 1/6 of the NOx emissions at takeoff.⁴⁹ However, over the full time of flight, most of the NOx emissions occur at cruise when the aircraft is high in the atmosphere, because it spends a majority of its time at cruise. The Air Resources Board's emission inventory only considers emissions released below an elevation of 3,500 feet. Emissions from aircraft at cruise are not considered to be a direct threat to public health. On the other hand, oxides of nitrogen above a certain elevation are believed to destroy upper atmospheric ozone. The exact altitude where NOx emissions begin to affect the ozone layer is unknown, but it is thought to be well above the tropopause. The ozone layer high in the atmosphere protects the earth from harmful ultraviolet radiation. Theories suggest that NOx compounds act catalytically to destroy upper atmospheric ozone. NOx compounds released in the lower atmosphere act to promote photochemical ozone formation.

Emissions of water (H_2O) from aircraft are also a concern. The products of combustion in complete combustion are carbon dioxide (CO_2) and water (H_2O) . Water exists in the lower atmosphere, but no water exists naturally at high altitudes. Emissions of water from aircraft flying at high altitudes forms contrails, which are trails of ice crystals. Water released in the atmosphere allows sunlight to pass through but it prevents radiation reflected by the earth from escaping into space. Therefore, these emissions are thought to increase the greenhouse effect.

The turbine inlet temperature generally varies with the load on a gas turbine. Since the load varies, the combustor operates in a range of temperatures. At full load the combustor operates near stoichiometric and the greatest NOx emissions are produced.

At idle the air/fuel ratio is nearly doubled and only half as much fuel is required for the same volume of air. The combustor burns leaner and the flame temperatures are lower. Unburned hydrocarbons and carbon monoxide tend to form more at lower temperatures. Smoke is more prevalent when the air/fuel mixture is rich.

The three areas where work has been conducted to reduce pollutant emissions from aircraft engines include using less polluting fuels, modifying the combustion process, and reducing the specific fuel consumption (reducing the

NOx and Ozone Layer

Water and Greenhouse Effect

53

EMISSION CONTROL

overall fuel consumption). The use of hydrogen as a fuel is being studied since it does not release carbon dioxide (a greenhouse gas). On the other hand, hydrogen releases 2.5 times as much water vapor as regular fuels.

Studies on combustion modifications of gas turbines are promising since the combustion in turbines is continuous and therefore easier to modify than reciprocating engines. Furthermore, the mixing air/fuel ratio and the temperature in the primary combustion zone can be selected without altering the turbine inlet temperature.⁵⁰

In the combustion process, pollutant formation can somewhat be divided into three areas in terms of combustion temperature and air/fuel ratio: low combustion temperatures with lean mixtures, stoichiometric combustion, and rich mixtures. Lean mixtures with lower temperatures tend to produce more carbon monoxide and unburned hydrocarbons, stoichiometric combustion produces more NOx, and rich mixtures tend to produce smoke. Within these ranges there are windows in the lean and rich areas with low pollutant formation.⁵¹

Higher NOx emissions will be produced if the mixture of fuel and air is not homogeneous. Clumps of fuel will burn hotter, creating more NOx emissions. Some of the methods used to achieve a homogeneous mixture include premixing and vaporizing the fuel in an external premix area before feeding it into the combustion chamber, or mixing the fuel without a premix section, but injecting it directly into the primary combusting zone where it is mixed. One problem with this method is that there is a narrow range of control compared to the typical combustor, making the system unreliable for widespread operation.

Rich-lean Staging

Studies have found that when operating with a rich mixture it is necessary to follow the rich-mix primary combustion stage with a second, lean-mix combustion stage. This technique, rich-lean staging, is achieved by the rapid addition of air to the mixture. This system also has problems with having an inadequate control range. Furthermore, cooling air films for the combustor cannot be used, since this would increase NOx production.

When operating with a lean mixture the rate of air fed into the head of the combustion chamber is increased by opening an annular gap between the compressor and combustor and closing off secondary air inlets. When the engine idles, the annular gap would be closed and the secondary air inlets would

EMISSION CONTROL

be open. The problem with this system is that a variable air intake requires moving parts in a hostile, high temperature environment. These parts would have to be made of new materials, and it would have a more complex combustion chamber.

With lean-burn combustion without external premixing, NOx emissions could be reduced 30%, with rich-lean stage combustion NOx emissions could be reduced 70%, and with lean combustion with external premixing emissions could be reduced 85%. The 85% reduction would only be possible under moderate pressure and air temperatures in the combustion chamber and therefore during the cruising part of flight. Much more work in the design, fundamentals of combustion, and metallurgy must be accomplished before an actual operating gas turbine with over 80% reduction in emissions will be achieved. Such an engine may not be developed until well into the 21st century.

307 ALTERNATIVE FUEL EMISSIONS

Using other fuels in gas turbines with lower flame temperatures is another method of reducing NOx emissions. The main problem with using alternative fuels is that they are generally not economical.

307.1 METHANOL

Methanol has a flame temperature of 3500°F which is more than 100°F less than the 3660°F flame temperature for natural gas. ⁵² Distillate oils have even higher flame temperatures than natural gas. Since NOx emissions are highly dependent on the combustion temperature, the lower combustion temperatures from methanol will produce less NOx.

In order to run methanol in a gas turbine some modifications must be done to the engine. The main modifications have to be done to the fuel delivery system for the methanol, including replacement of fuel manifolds and nozzles. Tests with methanol in gas turbines showed uncontrolled NOx emissions ranging between 41 to 60 ppmv. With methanol carbon monoxide and hydrocarbon emissions increase a small amount above those from a distillate fuel, but the output work is increased due to an increased mass flow rate through the turbine. The life of the

EMISSION CONTROL

gas turbine was increased and maintenance was decreased relative to engines running distillate oil because of a decrease in deposits forming in the combustor and turbine.⁵³

Another test of methanol in gas turbines was conducted at the University of California at Davis by the California Energy Commission in 1984. This engine had NOx emissions ranging between 22 and 38 ppm when running on methanol and 62 to 100 ppm when running on natural gas.⁵⁴ Gas turbine performance characteristics such as startup, acceleration and full power operation have been found to be adequate while using methanol.

307.2 COAL GAS

Coal gas is gaseous fuel derived from coal that has a flame temperature below that of natural gas. Combustor rig tests have shown that coal gas with the fuel bound nitrogen removed has a 70% reduction in NOx emissions relative to natural gas. Coal gas as a fuel for gas turbines was also demonstrated at the Cool Water plant in Southern California for five years during the early 1980's. The costs of coal gasification make coal gas unattractive.

Gas Turbines

401 FEDERAL REGULATIONS

The Federal Clean Air Act requires the U.S. Environmental Protection Agency (EPA) to establish new source performance standards (NSPS) for categories of sources which significantly contribute to air pollution. The NSPS apply both to new sources and to modifications to existing stationary sources of air pollution. The Clean Air Act directly prohibits operation of sources in violation of the NSPS.

NSPS

401.1 FEDERAL CLEAN AIR ACT

The Federal Clean Air Act Amendments were last developed in 1990. The main parts of the amendments include:

Title 1 - Nonattainment Areas

Mandates for the EPA to make regulations to bring nonattainment areas into attainment for CO, O₃, and particulate matter pollution.

Title 2 - Mobile Sources

Requirements for the EPA to issue regulations to reduce emissions from motor vehicles and automotive fuels.

Title 3 - Air Toxics

Requirements for EPA to issue standards to regulate 189 hazardous air pollutants.

Title 4 - Acid Rain

Mandates for EPA to issue new acid rain regulations, studies for NOx emissions, clean coal, and industrial SO₂ emissions.

Title 5 - Permits

Requirements for EPA to issue new rules for Permit approvals and source exemptions.

Titles 6+7 - Stratospheric Ozone + Global Climate Change Requirements for EPA to create new regulations and perform studies.

REGULATIONS

Title 8 - Miscellaneous

Provisions for electric cars, regulations for outer continental shelf operations and visibility studies.

Title 9 - Research

Studies addressing air pollution health effects, clean fuels, ecosystems and other items.

401.2 NSPS

EPA has the authority to delegate enforcement authority. EPA has delegated primary authority to several local districts in California and to the State in those districts not seeking delegation. Therefore, the districts can enforce the EPA's regulations.

Subpart GG

Federal air pollution regulations for gas turbines are located in the New Source Performance Standards in the Code of Federal Regulations, Title 40 Part 60 (40 CFR 60). The NSPS contain subparts ranging from A to VVV that give standards for a multitude of different processes. The Federal regulations for gas turbines are in Subpart GG - Standards of Performance for Stationary Gas Turbines.

The sections within this regulation include: 60.330 (Applicability and designation of affected facility), 60.331 (Definitions), 60.332 (Standard for nitrogen oxides), 60.333 (Standard for sulfur dioxide) 60.334 (Monitoring of operations) and 60.335 (Test methods and procedures).

401.2.1 Rule Applicability

The first section, 60.330, describes what gas turbines fall under the jurisdiction of the rule. The rule basically states that any stationary gas turbine with a heat input at peak load equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel, must meet the requirements in the rule. The word "stationary" is included in the regulation so that aviation gas turbines (i.e. jet engines) will not be affected by the rule.

Gas Turbines

The term "10.7 gigajoules per hour" is equivalent to 10.7 X 109 or 10.7 billion joules per hour. A joule is a unit of energy which is not used extensively, but this unit of energy can easily be converted to watts. One joule per second is equivalent to a watt and there are 3600 seconds in one hour.

Therefore: $(10.7 \times 10^9 \text{ joules/hour})(1 \text{ hour/}3600\text{sec})(1\text{watt/1joule/sec}) = 2.972 \times 10^6 \text{ watts or } 2.972 \text{ million watts}$. A million watts is the same as a mega watt (industry often uses energy in units of "mega watts"), therefore this is equivalent to 2.972 mega watts. The English system of units is still often used and these units are called "British Thermal Units" or Btu. The above limit in the regulation is equivalent to 10 million Btu/hour.

The rule also mentions the "lower heating value (LHV)" of the fuel. The gross heat that can be acquired from burning a fuel is called the "higher heating value (HHV)." The units of heating value are usually in Btu/lbm (Btu per pound-mass of fuel). The higher heating value includes the heat of vaporization of water, but the lower heating value does not. The higher heating value is therefore larger than the lower heating value. When a fuel is burned the main exhaust products are carbon dioxide and water. In the lower heating value the energy that was used to vaporize the water in the gas is not included. The heating value of the fuel affects the calculations that are made to determine the energy output of a gas turbine.

Part "b" in Section 60.330 states that gas turbines built or modified after October 3, 1977 are subject to the requirements of the rule. However, part "b" refers to two exemptions to this statement listed in Section 60.332 (e) and (j). If construction of a gas turbine commenced before October 3, 1982 and the heat input at peak load is greater than 10 million Btu/hr (10.7 gigajoules per hour) but less than 100 million Btu/hr (107.2 gigajoules per hour), based on the lower heating value of the fuel, the gas turbine is exempt from the NOx Section of the rule. This exemption can be found in Section 60.332(e) of the rule.

The other exemption is for gas turbines that were required by the September 10, 1979 Federal Register (44 FR 52792) to comply with NOx standards. These exempt turbines must have a heat input at peak load greater than 100 million Btu/hr (107.2 gigajoules per hour) and commenced construction or had a modification between October 3, 1977 and January 27, 1982. The exemption does not apply to electric utility stationary gas turbines. Few gas turbines are

LHV/HHV

Exemptions

REGULATIONS

able to make the requirements of this exemption, since most gas turbines are used to produce electricity. This exemption can be found in Section 60.332(j) of the rule.

401.2.2 Definitions

The next section, 60.331, contains definitions. They are briefly summarized here; see the regulation for the complete text.

Stationary gas turbine - Any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle seam/electric generating system that is not self propelled. It may be mounted on a vehicle for portability.

Simple cycle gas turbine - Any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

Regenerative cycle gas turbine - Any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

Combined cycle gas turbine - Any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

Emergency gas turbine - Any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source has been rendered inoperable by an emergency.

Ice fog - An atmospheric suspension of highly reflective ice crystals.

ISO (International Standards Organization) standard day conditions - 288° K temperature, 60% relative humidity, and 101.3 kilopascals pressure.

Efficiency - Gas turbine manufacturer's rated heat rate at peak load, in terms of heat input per unit of power output, based on the lower heating value of the fuel.

REGULATIONS

Peak load - 100% of the manufacturer's design capacity of a gas turbine at ISO standard day conditions.

Base load - The load at which a gas turbine is normally operated.

Fire-fighting turbine - Any stationary gas turbine that is only used to pump water for extinguishing fires.

Oil/gas production or oil/gas transportation gas turbines - Gas turbines used to provide power to extract crude oil or natural gas from the earth or to move crude oil, gas or refined products through pipelines.

Metropolitan statistical area (MSA) - An area defined by the Department of Commerce.

Offshore platform gas turbines - Gas turbines located on an offshore platform in the ocean.

Garrison facility - Any permanent military installation.

Gas turbine model - A group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

Electric utility stationary gas turbine - Any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system.

Emergency fuel - A fuel fired by a gas turbine only during a breakdown or other occurrence.

401.2.3 Standards for Nitrogen Oxides

Nitrogen oxides (NOx) are the main emissions of concern from gas turbines. Section 60.332 contains limitation of NOx emissions from gas turbines. The limit of NOx emissions from stationary gas turbines is determined by one of the following equations:

June 1996

REGULATIONS

NOx Limit Calculation

1. STD = 0.0075(14.4/Y) + F

or

2. STD = 0.015(14.4/Y) + F

Where:

STD = The allowable NOx emission (percent by volume at 15% oxygen on a dry basis)

Y = Manufacturer's rated heat rate at the manufacturer's rated load, or the actual measured heat rate based on the lower heating value of the fuel as measured at actual peak load for the facility. "Y" cannot exceed 14.4 kilojoules/watt hour

F = The percent NOx by volume from fuel bound nitrogen. Nitrogen is found in fossil fuels and when the fuel is burned, nitrogen oxides can form. Table 401.1 illustrates how to determine "F."

A. If a electric utility stationary gas turbine has a heat input at peak load that is greater than 100 million Btu/hr (107.2 gigajoules/hr) based on the lower heating value of the fuel, the allowable NOx emissions are computed with equation #1. This is in Section 60.332 (b) of the rule.

B. If the stationary gas turbine has a heat input at peak load equal to or greater than 10 million Btu/hr (10.7 gigajoules/hr) but less than or equal to 100 million Btu/hr (107.2 gigajoules/hr) based on the lower heating value of the fuel, the allowable NOx emissions are computed with equation #2. This is in Section 60.332 (c) of the rule.

Table 401.1 Determining F from Nitrogen Content of Fuel					
Fuel-bound nitrogen (% by weight) F (NOx % by volume)					
N <or=0.015< td=""><td>0</td></or=0.015<>	0				
0.015 <n<or=0.1< td=""></n<or=0.1<>					
0.1 <n<or=0.25< td=""></n<or=0.25<>					
N>0.25 0.005					
Note: N = the nitrogen content of the fuel (percent by weight)					

C. Stationary gas turbines with a manufacturers's rated base load at ISO conditions of 30 megawatts (30 million watts, which is equivalent to 107.2 gigajoules/hr) or less must meet the NOx limits calculated from equation #2, except as provided in Section 60.332 (b) of the rule (this is summarized above in "A"). See Section 60.332 (d) of the rule.

Note the first condition above is for "electric utility stationary gas turbines", but the other two conditions are for "stationary gas turbines."

Exemptions

Stationary gas turbines that use water or steam injection for the control of NOx emissions are exempt from NOx limits when ice fog becomes a traffic hazard, according to the owner or operator of the gas turbine (see Section 60.332 (f) of the rule).

Gas turbines that are used for emergencies, by the military for use other than a garrison facility, for military training, and for fire fighting are exempt from the NOx limits of the rule (see Section 60.332 (g) of the rule).

Stationary gas turbines that are used by manufacturer's to perform research and development for gas turbine emission control and efficiency improvements are exempt from NOx limits on a case-by-case basis as determined by the EPA Administrator

(see Section 60.332 (h) of the rule).

In geographical areas where mandatory water restrictions are required by government agencies because of drought conditions, exemptions from NOx limits may be granted on a case-by-case basis. Exemptions will only be granted while mandatory water restrictions are in effect (see Section 60.332 (i) of the rule).

Stationary gas turbines that burn natural gas and have a heat input equal to or greater than 10 million Btu/hr (10.7 gigajoules/hr) are exempt from NOx limits of the rule when being fired with an emergency fuel (see Section 60.332 (k) of the rule).

REGULATIONS

Regenerative cycle gas turbines with a heat input less than or equal to 100 million Btu/hr (107.2 gigajoules/hr) are exempt from the NOx requirements of the rule (see Section 60.332 (l) of the rule).

As discussed previously in Section 401.2.1 Rule Applicability, Section 60.332 (e) and (j) of the rule contains exemptions dealing with date of construction or modification of the gas turbine.

401.2.4 Standards for Sulfur Dioxide

Gas turbines can emit sulfur oxide emissions (SOx). Emission of sulfur oxides are dependent on the sulfur content of the fuel. Table 401.2 illustrates the sulfur dioxide emission limits.

The phrase "on a dry basis" in the rule means that when the volume of sulfur dioxide in the flue gas (exhaust) is calculated, water is not counted. When a fuel is burned, carbon dioxide (CO₂) and water (H₂O) are the primary compounds and would be the only ones formed in ideal, perfect, stoichiometric combustion. Unfortunately, pollutants such as carbon monoxide (CO), nitrogen oxide (NO), and sulfur dioxide (SO₂) are also formed. If the water is counted in the calculation to determine the percent sulfur dioxide in the flue gas, the number calculated will be lower than it would be on a dry basis.

401.2.5 Monitoring of Operations

The section on monitoring of operations, Section 60.334, describes how equipment should be operated to maintain compliance with the rule. The following is a brief description of the requirements in this section.

Table 401.2 Sulfur Dioxide Emission Limits for Gas Turbines				
Regulation Limit				
60.333 (a)	0.015% by volume at 15% oxygen on a dry basis.			
60.333 (b)	No burning any fuel which contains more than 0.8% by weight sulfur.			

Owners and operators of gas turbines, subject to the rule and using water injection to control NOx, must install and operate a system that continuously monitors and records the fuel consumption and the ratio of water injected to fuel burned. The system must have an accuracy between +/-5% (see Section 60.334 (a)).

Frequency of Monitoring NOx and SOx

If a gas turbine subject to the rule is supplied by fuel from a storage tank, the sulfur and nitrogen content of the fuel must be determined whenever fuel is transferred to the tank from another source (see Section 60.334 (b), and 60.334 (b),(1)).

If a gas turbine subject to the rule is supplied fuel without intermediate storage, the sulfur and nitrogen content of the fuel must be determined and recorded daily. Custom schedules for the determination of sulfur and nitrogen content can be developed, but they must be approved by the EPA Administrator (see Section 60.334 (b), and 60.334 (b),(2)).

Periods of Excess Emissions

This section of the rule describes how long a duration of violation in emissions requires the reporting of those emissions. It also has requirements regarding ice fog and emergency fuel. (Table 401.3)

Table 401.3 Duration of Excess Emissions that Requires Reporting				
Emission/item Time				
NOx 1 hour				
SOx Daily				
Ice fog Any				
Emergency fuel Any				

REGULATIONS

Nitrogen oxide excess emissions could be from a decrease in the water to fuel ratio, excessively high nitrogen in the fuel or high emissions. Reports of excess emissions must include the average water to fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and the nitrogen content of the fuel during the excess emission episode (Section 60.334(c), (1)).

When an ice fog episode occurs, the date and time that the air pollution system was deactivated and reactivated must be reported (Section 60.334(c), (3)).

When emergency fuel must be used, the type of fuel, the reason for the emergency, and the duration of the firing of the emergency fuel must be reported (Section 60.334 (c), (4)).

401.2.6 Test Methods and Procedures

This section of the rule contains procedures for calculating NOx emissions to determine compliance. It also tells the test methods that should be used to calculate the nitrogen and sulfur content of fuels.

In order to compute nitrogen oxide emissions, the owner or operator of the gas turbine must use methods that are accurate to within 5%. The methods used to determine NOx emissions and the nitrogen content of the fuel must be approved by the EPA Administrator (Section 60.335 (a)).

NOx Emission Rate Computation

Compliance with nitrogen oxide standards is computed by using the following equation: (Section 60.335 (c), (1))

 $NOx = (NOxo)(Pr/Po)^{0.5exp19(Ho-0.00633)}(288^{\circ}K/Ta)^{1.53}$

Where:

NOx = Emission rate of NOx at 15% O_2 and ISO conditions, volume percent NOxo = Observed NOx concentration (ppm by volume)

Pr = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure (mm Hg (mercury))

Po = Observed combustor inlet absolute pressure at test (mm Hg)

Ho = Observed humidity of ambient air (g H_2O/g air)

e = Transcendental constant (2.718)

Ta = Ambient temperature (°K)

Gas Turbines

Monitoring devices used to record the fuel consumption and the ratio of water to fuel being fired in the turbine must be used at 30, 50, 75, and 100% of peak load or at four points in the normal operating range of the gas turbine. The minimum point in the operating range and the peak load must be included and all loads must be corrected to ISO conditions. (Section 60.334 (a); 60.332 and 60.335 (c), (2))

Method 20 (40 CFR 60, Appendix A - Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines) must be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values must be 300 ppm of nitrogen oxide and 21% oxygen. NOx emissions must be determined at each of the required load conditions (30, 50, 75, and 100% or four different points including the maximum and minimum). (Section 60.335 (c), (3))

In order to determine compliance for the sulfur content of the fuel, ASTM D 2880-71 must be used for liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 must be used for gaseous fuels. Another method approved by the EPA administrator that is accurate to within 5% can also be used to determine compliance. (Section 60.335 (d))

The owner or operator may use reference methods other than the ones in the rule as long as they are approved by the EPA administrator. (Section 60.335 (f) and 60.335 (f), (1))

401.3 NESHAPS

At the federal level there are also standards regarding the emissions of toxic compounds called the National Emission Standards for Hazardous Air Pollutants (NESHAPS). These regulations have Subparts ranging from A to Y. The NESHAPS contain standards for compounds such as beryllium, asbestos and benzene.

Method 20

ASTM

REGULATIONS

401.4 ACID RAIN PROVISIONS

Generally, non-utility combustion turbines that commenced operation prior to November 15, 1990 are not affected by the acid rain rules. Any combustion turbine that commenced operation after this date and sells electricity, may be an affected unit. Units that produce less than 25 MW of electricity for sale may be eligible to apply for an exemption from some of the acid rain rule requirements.

An affected unit must comply with acid rain regulations, including holding allowances sufficient to cover its annual SO₂ emissions, obtaining an acid rain Permit (which is part of the unit's general Permit), having a Designated Representative (DR), and installing and operating systems that continuously monitor emissions of SO₂, NOx and other related pollutants.

The only way an affected unit may avoid the full requirements of the acid rain program is by qualifying for an "exemption." Even if a unit is awarded an exemption, it is subject to certain minimum requirements. Exemptions and applicability determinations are made by the U.S. EPA Acid Rain Division in Washington, D.C. For more detailed information on the regulations, please refer to 40 CFR 72-78, or call the Acid Rain Hotline at (202) 233-9620.

40 CFR 72-78

Parts 72, 73, 74, 75, 76, 77, and 78 in the Code of Federal Regulations Title 40 deal with acid rain. Part 72 is the Permits Regulation, Part 73 is the Sulfur Dioxide Allowance System, Part 74 is Sulfur Dioxide Opt-Ins, Part 75 is the continuous emission monitoring and reporting requirements for affected units, and Part 76 is the Acid Rain Nitrogen Oxides Emission Reduction Program (This is only for coal fired devices).

Part 72 Permits Regulation

Subpart A-Acid Rain Program General Provisions - Sections 72.1 to 72.13

- 72.6 Applicability (gas turbines [utilities] that must conform to regulation) (a)1 and 2 All fossil fuel fired devices listed in Table 1, 2 or 3 of 73.10. (a)3, i and ii All other fossil fuel fired devices except those that are new or did not have a capacity over 25 MW (megawatts) of electric power on 11/15/90 but did after 11/15/90.
- (a)3, iii Simple cycle gas turbines built as of 11/15/90, that had auxiliary firing added on after 11/15/90.

- (a)3, iv Previously exempt cogeneration facilities that sold during any three year period since 11/15/90 more than 1/3 of its potential electrical output capacity and more than 219,000 MW.
- (a)3, v and vi Fossil fuel fired devices that failed to meet the definition of a "qualifying facility" or an "independent qualifying facility" by 11/15/90.
- (a)3, vii A fossil fuel fired device that qualifies as a solid waste incinerator, but during any three years after 11/15/90 consumed 20% or more fossil fuel on a Btu basis.

Exemptions

- (b)1 Simple Cycle gas turbines that commenced operation before 11/15/90 are exempt.
- (b)2 Fossil fuel fired devices that commenced operation before 11/15/90 and do not generate more than 25 MW of electricity.
- (b)3 Fossil fuel fired devices that did not generate electricity for sale during 1985, as of 11/15/90, or currently.
- (b)4, i Cogeneration facilities that commenced construction on or before 11/15/90 to supply equal to or less than 1/3 of its potential electrical output capacity, or equal to or less than 219,000 MW-hrs. on an annual basis.
- (b)4, ii Cogeneration facilities that commenced construction after 11/15/90 and supply equal to or less than 1/3 of its potential electrical output capacity or equal to or less than 219,000 MW-hrs. on an annual basis.
- (b)5, i "Qualifying facilities" (see Section 72.2) that have one or more power purchasing commitments to sell at least 15% of their total net output capacity as of 11/15/90.
- (b)5, ii "Qualifying facilities" (see Section 72.2) that consist of one or more fossil fuel fired devices with a total net output capacity not exceeding 130% of the total planned net output capacity. If emission rates of the units are not the same the Administrator may exercise discretion in determining exempt units.
- (b)6, i "independent power production facilities" (see Section 72.2) that had one or more power purchasing commitments to sell at least 15% of their total net output capacity as of 11/15/90.
- (b)6,ii "independent power production facilities" (see Section 72.2) that consist of one or more fossil fuel fired devices with a total net output capacity not exceeding 130% of the total planned net output capacity. If emission rates of the units are not the same the Administrator may exercise discretion in determining exempt units.
- (b)7 Solid waste incinerators exemptions.
- (b)8 "Non-utility units" (see Section 72.2) are exempt.

REGULATIONS

- (c) Petitioning EPA Administrator for applicability
- 72.7 New Units Exemption (those with a capacity less than 25 MW and burn fuel with less than 0.05% sulfur.)
- 72.8 Retired Units Exemption
- 72.9 Standard Requirements
- (a)1, i The designated representative of each source must submit a complete acid rain permit application.
- (b) Monitoring requirements
- (c) Sulfur dioxide requirements
- (d) NOx requirements
- (e) Excess emission requirements
- (f) Recordkeeping and reporting requirements
- (g) Liability
- (h) Effect on other authorities

Subpart B-Designated Representative - Sections 72.20 to 72.25

Subpart C-Acid Rain Permit Applications - Sections 72.30 to 72.33

Subpart D-Acid Rain Compliance Plan and Compliance Options - Sections 72.40 to 72.44

Subpart E-Acid Rain Permit Contents - Sections 72.50 and 72.51

Subpart F-Federal Acid Rain Permit Issuance Procedures - Sections 72.60 to 72.69

Subpart G-Acid Rain Phase II Implementation - Sections 72.70 to 72.74

Subpart H-Permit Revisions - Sections 72.80 to 72.85

Subpart I-Compliance Certification - Sections 72.90 to 72.96

Part 73 Sulfur Dioxide Allowance System

Subpart A-Background and Summary - Sections 73.1 to 73.3

73.2 Applicability

- (a) Owners, operators, and designated representatives of regulated sources under Section 72.6 (previous applicability section discussed for part 72)
- (b) New "independent power producers" (see Part 72 definitions)
- (c) Any owner of a regulated unit that may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program
- (d) Any small diesel refinery as defined in 72.2 (definitions)
- (e) Any other person (defined in 72.2 definitions) who purchases, holds, or transfers allowances.

Standard requirements - The standard requirements of the previously mentioned Subpart 72 apply to Subpart 73 (Section 73.3 General). The requirements state that a permit application must be submitted.

Subpart B-Allowance Allocations - Sections 73.10 to 73.27

Subpart C-Allowance Tracking System - Sections 73.30 to 73.38

Subpart D-Allowance Transfers - Sections 73.50 to 73.53

Subpart E-Auctions, Direct Sales, and Independent Power Producers Written

Guarantee - Sections 73.70 to 73.77

Subpart F-Energy Conservation and Renewable Energy Reserve - Sections

73.80 to 73.86

Subpart G-Small Refineries - Section 73.90

Part 74-Sulfur Dioxide Opt-Ins

Subpart A-Background and Summary - Section 74.1 to 74.4

74.2 Applicability

Combustion or process sources that are not regulated under Section 72.6 (applicability) that are operating and located in the lower 48 States or the District of Columbia may submit an Opt-In permit. Units under 72.7 or 72.8 under written exemption and combustion or process sources are not eligible.

Subpart B-Permitting Procedures - Sections 74.10 to 74.19

Subpart C-Allowance Calculation for Combustion Sources - Sections 74.20 to 74.28

Subpart D-Allowance Calculation for Process Sources (Reserved)

Subpart E-Allowance Tracking and Transfer and End of Year Compliance - Sections 74.40 to 74.50

Subpart F-Monitoring Emissions: Combustion Sources - Sections 74.60 and 74.61

Subpart G-Monitoring Emissions: Process Sources (Reserved)

Part 75-Continuous Emission Monitoring (40 CFR 75)

Subpart A-General - Sections 75.1 to 75.8

75.2 Applicability

(a) All units that are subject to acid rain emissions limitations or reduction requirements for sulfur dioxide or NOx. exemptions:

REGULATIONS

- (b) New units that have a nameplate capacity of 25 MW or less and burn fuel with a sulfur content of 0.05% by weight or less.
- (b)2 Units not subject to the requirements of the acid rain program (see 72.6).
- (b)3 A unit subject to the regulation that has been issued a written exemption under 72.8 and granted an exception granted under 75.67.

Subpart B-Monitoring Provisions - Sections 75.10 to 75.18

75.10 General

- (a) The owner or operator shall measure opacity, SO₂, NOx, and CO₂ for all units subject to the regulation.
- 75.11 Monitoring SO,
- 75.12 Monitoring NOx
- 75.13 Monitoring CO₂
- 75.14 Monitoring opacity
- 75.16,17,18 Monitoring for bypass stacks, multiple stacks and other provisions.

Subpart C-Operation and Maintenance Requirements - Sections 75.20 to 75.24

Subpart D-Missing Data Substitution Procedures - Sections 75.30 to 75.36

Subpart E-Alternative Monitoring Systems - Sections 75.40 to 75.48

Subpart F-Recordkeeping Requirements - Sections 75.50 to 75.56

Subpart G-Reporting Requirements - Sections 75.60 to 75.67

Part 77-Excess Emissions

- 77.1 Purpose and Scope
- -Excess emission offset planning and offset planning requirements. Applies to owners operators and designated representatives subject to the Acid Rain Program.
- 77.2 General
- 77.3 Offset Plans for Excess Emissions of Sulfur Dioxide
- (a) Applicability Any owner or operator subject to the regulation that has emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the "Allowance Tracking System" (see part 72.2 Definitions) account.
- (b) Deadline No more than 60 days after the end of any calendar year which a unit had excess sulfur dioxide emissions.
- (c) Number of Plans
- (d) Contents of Plan

Gas Turbines

- 77.4 Administrator's Action on Proposed Offset Plans
- 77.5 Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide
- 77.6 Penalties for Excess Emissions of Sulfur Dioxide and Nitrogen Oxides

Part 78-Appeal Procedures for Acid Rain Program - Sections 78.1 to 78.20

401.5 TITLE V OPERATING PERMIT PROGRAM

Title V is a federal EPA operating permit program to track emissions from large sources (Title 40 CFR Part 70). Sources with over 100 tons/year of emissions, over 10 tons/year of hazardous pollutants, or sources subject to non-attainment provisions are subject to Title V.

401.6 PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

Prevention of Significant Deterioration is a program designed to prevent the deterioration of air quality, especially in areas that are in attainment or relatively free of air pollution.

402 STATE REGULATIONS

State laws and statutes applicable to air pollution are in the California Health and Safety Code. Applicable Health and Safety Code requirements are in Appendix B.

Specific State regulations regarding air pollution are developed by the California Air Resources Board and are included in the California Code of Regulations (CCR). Title 13 contains regulations for mobile sources (cars, trucks etc.), Title 17 contains stationary source regulations, and Title 26 contains toxics regulations. The Air Resources Board of the State of California primarily performs regulation and enforcement for mobile sources, consumer products, fuels, and abrasive blasting.

California Health & Safety Code

CCR

REGULATIONS

402.1 CALIFORNIA CLEAN AIR ACT

There is also a California Clean Air Act which went into effect in 1988. It basically requires the following:

- 1. The attainment of the State ambient air quality standards by the earliest practicable date.
- 2. All districts in violation of the State ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide standards must submit attainment plans every three years.
- 3. The California Air Resources Board must adopt the most effective emission controls possible for motor vehicles, fuels, consumer products, and mobile sources.
- 4. Districts subject to planning requirements must reduce emissions 5% a year until the relevant standard is achieved.
- 5. Rules and regulations within air basins must be uniform to the extent practicable, and the districts must coordinate individual planning efforts so that regional air quality issues are adequately addressed.

402.2 STATE IMPLEMENTATION PLAN (SIP)

The State Implementation Plan (SIP) is a plan that must be delivered to the federal EPA describing how the state will run its air quality control programs in order to attain the National Ambient Air Quality Standards.

403 LOCAL (DISTRICT) REGULATIONS

Most of the regulation and enforcement is conducted by county air pollution control districts (APCDs) or multi-county air quality management districts (AQMDs). Districts regulate with their rules and by issuing Permits to Operate to companies owning or operating pollution generating equipment. Permits to Operate help simplify requirements in complex regulations for facility operators and owners so they can usually comply with most requirements by following their Permit. When a facility does not comply with a Permit or rule it may be

REGULATIONS

given a Notice of Violation (NOV) and fined. Districts can also enforce the EPA rules and many have directly adopted the NSPS and NESHAPS regulations. In some cases district regulations are more stringent than the EPA's. District regulations cannot be less stringent than the EPA's.

403.1 DISTRICT STATIONARY GAS TURBINE REGULATIONS

Most of the heavily populated districts and districts with large industries have rules exclusively for stationary gas turbines. As of the time of the printing of this manual, the Bay Area Air Quality Management District (BAAQMD), Mojave Desert Air Quality Management District (MDAQMD), Sacramento Metropolitan Air Quality Management District (SMAQMD), San Diego Air Pollution Contro District (APCD), South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD), Ventura County Air Pollution Control District (APCD), and the Yolo-Solano Air Quality Management District all have rules for gas turbines. Districts that don't have a rule for stationary gas turbines simply use their fuel burning equipment rule or control of NOx rule and their sulfur content of fuels rule to prevent excessive emissions from them. Districts can also use the Federal NSPS regulation for gas turbines. Some of the district rules are directly adopted from the NSPS and have almost the same requirements.

Most of the rules in different districts are set up in a similar fashion. In general, they usually begin with general information about the regulation, definitions or an applications section. The definitions section describes the meanings of important words as they pertain toward the rule. The applications section describes what kind of equipment applies to the rule. In gas turbine regulations, districts may have a statement such as "the provisions of this rule shall apply to all existing stationary gas turbines 0.3 megawatt (MW) and larger as of August 4, 1989." The standards section describes the emission limitations. Note that the standards for the concentration of NOx emissions in district and federal regulations are at 15% O₂ on a dry basis. This prevents a facility from complying with emission concentrations in the exhaust by diluting it with air. "On a dry basis" also means that water in the exhaust will not be counted when emission concentrations are determined. Tables 403.1 to 403.8 summarize the standards of the districts with regulations on stationary gas turbines. For specific requirements refer to your district rule.

REGULATIONS

Table 403.1 BAAQMD - Main Standards from Regulation for Gas Turbines (effective 1/1/97)						
Regulation	Power rating (P) in MW	SCR		CR Limit, ppmv (corrected to 15% O2 on a dry basis)		
		•	Gas	Refinery fuel gas	Non- gaseous	
9-9-301.1	Equal or over 0.3, less than 10.0		42	55	65	
9-9-301.2	Equal or over 10.0	no	15		42	
9-9-301.3		yes	9		25	
9-9-302	Equal or over 4.0 (operating time < 877 hrs/year)		42		65	
9-9-305 (low NOx turbines)	PTO before 5/5/93, 25ppm or less BACT was required	no	18		42	
	Effective	5/31/9	95			
9-9-304 (Interim RACT)	(Interim (operating time > 877		42		65	
	Effective	e 1/1/9	6			
9-9-303 Equal or over 10, less than 30 to 301.2)		no	25		42	
	Effective	e 1/1/0	0			
9-9-303.2	Equal or over 10, less than 30	no	15		42	

Table 403.2 Mojave Desert AQMD - Main Standards from Regulation for Gas Turbines					
Regulation	Stationary gas turbine type	NOx emission limit at 15% oxygen or a dry basis			
		Gas fired	Oil fired		
1159 C (1) a	Units not subject to the Federal NOx RACT limits below in C(1)(b)	42 ppmv	65 ppmv		
1159 C (1) b	Southern CA Gas Co. Turbine model LM 1500	90 ppmv			
1159 C (1) c, ii	all	Oil (kerosene, jet fuel, and distillate) fired gas turbines must have a sulfur content less than 0.05%			

Table 403.3 Sacramento AQMD - Main Standards from Regulation for Gas Turbines					
Regulation	gulation Power rating Hours of (MW) SCI	SCR	NOx limit (corrected to 15% O2 on a dry basis)		
		per year		Gaseous fuel	Liquid fuel
413 301.1, 301.2 (RACT)	0.3 or greater	any		42 ppmv	65 ppmv
413 302	0.3 to < 2.9	any		42 ppmv	65 ppmv
(BARCT)	2.9 or more	less than 877		42 ppmv	65 ppmv
	2.9 to < 10.0	877 or over		25 ppmv	65 ppmv
	10.0 or over	877 or over	no	15 ppmv	42 ppmv
	10.0 or over	877 or over	yes	9 ppmv	25 ppmv
413 303.1	Gas turbines rated with an output of less than 10 MW must have approved equipment operated and maintained in calibration that continuously measures and records control system operating parameters, and elaspsed time of operation.				
413 303.2	Units of 10MW or more, that operated over 4000 hrs./year before the three years before 4/6/95 must have approved equipment that continuously measures and records control system operating parameters, elasped time of operation, and NOx corrected to 15% O2 on a dry basis.				
413 303.3		_		es must install h turbine by 4/6	

Table 403.4 San Diego APCD - Main Standards from Regulation for Gas Turbines						
Regulation	Power rating NO2 emission limit at 15% oxyego on a dry basis					
		Gaseous fuel	Liquid fuel			
69.3, (d), (1), i and ii	engines)	42 ppmv	65 ppmv			
	over 0.3 (new engines)					

Table 403.5	Table 403.5 SCAQMD - Main Standards from Regulation for Gas Turbines					
District	Regulation	Power rating in MW	SCR	Reference NOx limits (ppm) (effective 12/31/95)		
SCAQMD	1134c,1	0.3<2.9		25		
		2.9<10.0		9		
			no	15		
		10.0 and over		9		
			no	12		
		60 and over,	no	15		
	ļ	combined cycle		9		
Efficiency = 3	3413(100%)/a	ence limit)Efficien actual heat rate at rated efficiency a	HHV (I	Btu/kWhr)		
Compliance limit = Allowable NOx emissions (ppm by volume) Reference limit = NO emission limit (ppm by volume), at 15% O2 on a dry basis, averaged over 15 consecutive minutes		om by O2 5	Efficiency = Efficiency of gas turbine without downstream recovery equipment, from the actual heat rate corrected to HHV of the fuel, at peak load; or manufacturer's rated efficiency after correction from LHV to HHV - whichever is higher. Efficiency cannot be less than 25%, but if it is, it is assigned a value of 25%.			

400 - 22 June 1996

Table 403.6 SJVUAPCD - Main Standards from Regulation for Gas Turbines						
Regulation	Power rating (MW)	1 5 1			Compliance limit, ppm NOx (at 15% O2 on a dry basis)	
				Gas fired	Oil fired	
4703, 5.0,	4 and over	<877		42 ppm	65 ppm	
5.1, 5.1.1	0.3 to 10.0	>or=877	no	42 ppm	65 ppm	
	10.0 and		no	[(15)Eff]/25	[(42)Eff]/25	
	over		yes	[(9)Eff]/25	[(25)Eff]/25	
	Sufur content	of oil must be	less th	nan 0.05%		
	Gas turbine m type	anufacturer a	ınd			
4703, 5.0, 5.1, 5.1.2	General Electi quiet combust		rith	[(18)Eff]/25	[(42)Eff]/25	
·	Solar Saturn awith centrifuga	,		50	50	
				Compliance limit CO emissions (ppm) (corrected to 15% O2 on a dry basis)		
4703, 5.0,	Units subject to 5.1.1			200		
5.2	General Electric Frame 7			25		
	General Elect quiet combus		vith .	52		
	Solar Saturn 1100 hp gas turbine with centrifugal compressor			250		
4703, 5.1, 5.1.1 Eff can be found from Eff1 or Eff2 Eff1 = [3423 Btu/kWhr/(actual heat rate at HHV)Btu/kWhr](100%) Eff1 = % efficiency of the gas turbine without downstream recovery equipment from the actual heat rate, corrected to standard conditions and HHV, at peak load Eff2 = [(Effm)LHV]/HHV Eff2 = The efficiency from the manufacturer "Effm" corrected from LHV to HHV at peak load						

REGULATIONS

	Table 403.7 Ventura - Main Standards from Regulation for Gas Turbines				
Regulation	Power rating (MW)	rating Hours of Soperation	SCR	NOx limit ppmv, (corrected to 15% O2 on a dry basis)	
		per year		Gaseous fuel	Liquid fuel
74.23 B, 1	0.3 to <2.9			42	65
	2.9 to <10.0		no	[(25)E]/25	65
	10.0 and		yes	[(9)E]/25	[(25)E]/25
	over		no	[(15)E]/25	[(42)E]/25
	4.0 and over	less than 877		42	65
	Efficiency (E) is calculated by: E = [(MRE)(LHV)]/HHV MRE = Manufacturer's rated thermal efficiency (continuous at LHV) LHV = The lower heating value of the fuel HHV = The higher heating value of the fuel E cannot be less than 25%, if it is, E is assigned a value of 25%				
74.23 B, 2, a and b	Equipment that continuously operates, measures, and records control system operating parameters, and elaspsed time of operation is required.				
74.23 B, 2, c	Units over 10MW, that operated over 4000 hrs./year before 5/31/95 must have equipment that continuously measures and records NOx corrected to 15% O2 on a dry basis, averaged over any 3 consecutive hours.				
74.23 B, 3	Owners or Operators of gas turbines must submit plans to the APCO for complying with the emission limit of 74.23 B, 1.				
74.23 B, 4	No emissions of ammonia in excess of 20 ppmv from any emission control device subject to the limits of 74.23 B, 1.				
74.23 B, 5	Units rated at over 20 MW with water injection only where the exhaust gases are used to dry paper must meet the following NOx limit (ppmv): (20xE)/25 (gaseous fuel) or (42xE)/25 liquid fuel				

June 1996

Tal	Table 403.8 Yolo-Solano AQMD - Main Standards from Regulation for Gas Turbines					
Regulation	Power rating (MW)	Hours of operation	SCR	R Compliance limit, ppm NOx (at 15% O2 on a dry basis)		
		·		Gas fired	Oil fired	
Reg II, Rule	0.3 to <2.9			42 ppm	65 ppm	
2.34, 301	4 or more	<877		42 ppm	65 ppm	
	2.9 to <10.0			[(25)Eff]/25	65 ppm	
10.0 and over			yes	[(9)Eff]/25	[(25)Eff]/25	
		no	[(15)Eff]/25	[(42)Eff]/25		
Reg. II Rule 2.34, 301.1						

REGULATIONS

Between different districts, the sections in a regulation that appear after the standards section can vary somewhat, but they generally have the same kind of information. Some regulations have an administrative requirements section. Other rules such as the South Coast AQMD rule on gas turbines have a compliance schedule section and an emission control plan section. These parts of the rules often have information on different requirements of the rule that must be complied with over time. Items in these parts of the rule may also require owners or operators of the equipment to submit plans by specific dates to illustrate how they will comply with the rule. Many district rules then often describe equipment monitoring requirements and recordkeeping requirements in the monitoring and recordkeeping section.

Besides a district's gas turbine rule, other rules such as those that regulate carbon monoxide, particulate and sulfur dioxide emissions can apply to gas turbines.

403.1.1 Exemptions

District rules often have an exemption section where equipment that does not have to comply with the rule is described. This section may occur at the end of the regulation, but some district rules have it at the beginning. Some typical situations where gas turbines are exempt and do not have to comply with regulations are when gas turbines are for emergencies and operate less than a specific amount of time per year (such as 200 hours). Gas turbines used for laboratory research, firefighting, or flood control are often exempt from regulations. Peaking turbines, which are gas turbines that are used only during high electrical demand periods, which often occurs on hot summer days, are often exempt if they operate under 200 hrs/year or other specified time.

Gas turbines are usually exempt when they are first started, especially when they are new. When a gas turbine is started emissions can be high and it takes time for catalysts to warm up and become effective. New gas turbines must be run for a period of time to burn out contaminants that are in the system. New gas turbines are run without a catalyst so emissions are high, but the engine must run without the catalyst or the contaminants in the system will clog it. The start-up period for a gas turbine is often referred to as the thermal stabilization period. The thermal stabilization period is generally one or two hours. Gas turbines

Gas Turbines

may also be exempt from regulations when there are unplanned load changes or planned shutdowns of the unit. These periods of time may also be one to two hours.

403.2 VISIBLE EMISSIONS

All of the local air pollution control districts in California have a visible emissions prohibitory rule. These rules vary in wording, but in almost all cases they express the following:

- "... no person shall discharge into the atmosphere from any source whatsoever any contaminant, other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour which is:
- (a) As dark or darker in shade as that designated as No. 1 (or 20% opacity) on the Ringelmann Chart, as published by the United States Bureau of Mines,
- (b) Or of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subdivision (a)."

The State standard for visible emissions (Section 41701, California Health and Safety Code) is No.2 on the Ringelmann Chart, or 40% opacity.

The Ringelmann Chart is a device used for determining whether emissions of smoke are within established limits or standards of permissibility (statutes and ordinances) with reference to the Ringelmann Chart. Smoke density in a plume is compared with a series of graduated shades of gray to black on the Ringelmann Chart, and the smoke density is thus judged by the viewer. Many districts use a more restrictive limit of Ringelmann 1 or 20% opacity (See Table 403.9). EPA Reference Method 9 describes in detail how such visible emissions evaluations should be properly performed, and how to be certified to perform them.

The Compliance Division of the California Air Resources Board trains and certifies government and industry personnel in visible emissions evaluations at its popular "Fundamentals of Enforcement" class which is offered four times a year. Certified personnel are required to recertify every six months in order to demonstrate ongoing evaluation skill.

Ringelmann Chart

Method 9

REGULATIONS

Table 403.9 Relationship Between Light Transmission, Ringelmann and Opacity					
% Light Ringelmann Opacity Transmission					
0	5	100			
20	4	80			
40	3	60			
60	2	40			
80	1	20			
100	0	0			

When reducing the data, the inspector should aggregate the readings taken at 15-second time intervals where the opacity was observed to exceed the Ringelmann limit. Every aggregate of over three minutes of such readings, made in a one hour period, constitutes a violation. This data reduction method reflects the visible emissions limitation in California Healthy and Safety Code (H&SC) Section 41701. Note that this procedure of data reduction results in more stringent emissions limitations than the Federal method as stated in Method 9. According to Method 9, opacity is determined as an average of 24 consecutive observations recorded at 15-second intervals (i.e., six consecutive minutes of readings, averaged).

403.3 SULFUR OXIDE EMISSIONS

Some of the district rules specifically for gas turbines limit the amount of sulfur in the exhaust gas by the sulfur content of the fuel. The amount of sulfur is usually limited by the percent-by-weight of sulfur in the fuel. The percent-by-weight of sulfur in a fuel may be limited in a fuel burning rule or a fuel burning

REGULATIONS

equipment rule. Districts that do not have a gas turbine rule or do not have a sulfur oxides limit in their gas turbine rule can apply the fuel burning equipment rule or other rules to the source.

Some district sulfur emissions rules limit the stack discharge concentration to a specified ppm from any combustion operation. Other rules require that a process not emit enough sulfur compounds to exceed the State or federal standards at the ground level (0.05 ppm, by volume, for 24 hours average, or 0.25 ppm, by volume, for 1 hour average).

403.4 DISTRICT PERMITS TO OPERATE

Under the authority of the California Health and Safety Code, and in order to comply with the California State Implementation Plan and New Source Performance Standards where applicable, the districts issue Permits to Operate which contain conditions for the operation of industrial processes and emission control equipment. The Permit conditions in a Permit to Operate generally reflect the requirements of rules that apply to a source.

Facilities must function within the parameters stated in the Permit to Operate issued by the district. Permits must be posted on the equipment, where applicable, and they must be current. If these conditions are not adhered to, it is a violation.

Permits have an equipment list, listing the equipment it covers. It is a violation to operate pollution generating or control equipment that is not permitted. It is also a violation to make modifications to permitted equipment without district approval. When new equipment or modifications are required, a district will issue an Authority to Construct to the owner or operator of the equipment.

Whenever a company must make a modification to its equipment or buy new equipment, it should notify its local district immediately. A district can usually accommodate a source even when modifications must be made in a short period of time.

Authority to Construct

June 1996

REGULATIONS

An Authority to Construct will list the equipment to which it applies and it will list conditions similar to those on a Permit to Operate. After the new equipment is modified or constructed the district may conduct a source test and issue a Permit to Operate.

Typical Permit Conditions

Some typical conditions stated on a Permit to Operate on an operation using a gas turbine include:

- 1. Fuels that can be burned in the gas turbine.
- 2. The number of hours of operation allowed per year (especially for emergency engines and peaking turbines).
- 3. Range of allowable water or steam injection rates.
- 4. Range of allowable ammonia injection rates.
- 5. Emission limits.
- 6. Recordkeeping requirements.
- 7. Requirements for continuous emission monitors.

403.5 EQUIPMENT BREAKDOWN PROVISIONS

Most districts have an equipment breakdown (or excusable equipment malfunction) rule. The rule enables a source qualifying under stated conditions to avoid enforcement action when that source fails to comply with air pollution regulations as a result of a malfunction of any air pollution control equipment or related operating equipment. Malfunctions of in-stack monitoring equipment are also addressed in the rule.

Sources should keep a copy of the breakdown rule at the facility. They should also be familiar with their responsibilities in the event of an equipment malfunction.

Gas Turbines

The conditions that a malfunction must meet in order to qualify for district breakdown provisions vary between districts. Typically, the following conditions must be met in order to qualify for protection under the district's breakdown rule:

- 1. The breakdown must result from a failure that was unforeseeable;
- 2. It must not be the result of neglect or disregard of any air pollution control law, rule, or regulation;
- 3. It must not be intentional, or the result of negligence;
- 4. It must not be the result of improper maintenance;
- 5. It must not constitute a nuisance; and
- 6. It must not be an abnormally recurrent breakdown of the same equipment.

District rules also list a number of procedures which must be followed in reporting the breakdown in a timely manner to the district. If the breakdown is not reported to the district within the allowed time period, as stated in the rule, a separate violation occurs, for which enforcement action is appropriate.

When a breakdown is reported to the district it is recorded in the district's breakdown log. Sources must provide the district with the following information:

- 1. The source's name and location, and the source's contact name(s) and phone number;
- 2. The specific equipment affected by the breakdown;
- 3. The specific equipment that failed;
- 4. The date and time that the breakdown occurred;
- 5. The date and time that the breakdown is being reported to the district; and
- 6. The source's proposed action.

Breakdown Conditions

Information Provided by Source to District

REGULATIONS

Upon receipt of a breakdown report, the district performs an investigation to determine whether the malfunction meets the prescribed breakdown conditions. This investigation includes an on-site inspection of the malfunctioning equipment. If the inspector does not find a breakdown condition at the source, they may take appropriate enforcement action. This may include fines, an abatement order, or an injunction against further operation.

If a source files a breakdown report which is false or without probable cause, or claims a malfunction to be a breakdown occurrence, this shall constitute a separate violation. The burden of proof shall be on the source to provide sufficient information that a breakdown did occur. If the source fails to do this, the district will undertake appropriate enforcement action.

A source with a breakdown must take immediate steps to correct the equipment malfunction as quickly as possible. If a source finds that a malfunction cannot be repaired within the district's allowable duration of a breakdown, the source may file for an emergency variance in order to avoid enforcement action.

Details Submitted to APCO by Source

District rules require sources to submit in writing the following details to the district air pollution control officer within a stated time period of the correction of the breakdown occurrence:

- 1. The duration of excessive emissions;
- 2. An estimate of the quantity of excess emissions;
- 3. A statement of the cause of the occurrence;
- 4. Corrective measures to be taken to prevent recurrences; and
- 5. Proof of the source's return to compliance, including the date and time that the breakdown was corrected.

Besides the information mentioned above, the district log will also include the following items, some of which will be completed as the case continues:

1. A confirmation that the breakdown is allowable under district rules;

- 2. The name of the district investigator;
- 3. The initial inspection file number;
- 4. The compliance confirmation inspection file number;
- 5. The date that the breakdown correction report was filed by the source; and
- 6. An indication if a variance was requested.

403.6 VARIANCES

A source may petition for a variance if either of the following is true:

- 1. Pollution control equipment has broken down and meets the criteria for breakdown condition under district rules; however, the source operator finds that it will take longer to repair the breakdown than provided for under the district breakdown rule.
- 2. A source finds itself to be out of compliance, is found to be out of compliance, or expects to soon be out of compliance, with any air pollution control district rule or regulation, or with Section 41701 of the California Health and Safety Code (H&SC). Table 403.10 illustrates the main types of variances. For complete information on variances, please consult the Health and Safety Code. The table provided here is only a quick summary.

A source may petition for variance when they find themselves in violation of a district rule or regulation despite attempts made to cure the violation, or if a breakdown situation occurs. If a rule or regulation includes an Increments of Progress Schedule and a source cannot comply with the schedule in the rule or regulation, the source must apply for a modification of the schedule in accordance with H&SC 42357, except if the application requests a change in the final compliance date, which then makes them subject to the requirements of a variance as provided in H&SC 42352.

Table 403.10 Variances			
Type of Variance	Effective Time Span	Noticing Requirements	Other Considerations
Emergency	30 day maximum	None	1 member may issue. Hearing Board determines eligibility for emergency
Short	90 day maximum	10 day minimum to APCO, air basin, EPA, ARB, and petitioner	1 Hearing Board member may hear if district population < 750,000, unless a public member objects
Interim	90 day maximum or until next Hearing Board meeting (whichever first)	Reasonable notice to APCO and petitioner	Same as short variance
Regular	1 year maximum unless schedule of increments of progress included	30 day minimum (15 if population < 750,000) to APCO, air basin district, ARB, EPA petitioner and any interested public	Public notice of hearing in at least one newspaper of general circulation in district
Modification of final compliance date (extension)	Determined by Hearing Board	Same as regular variance	Same as regular variance
Modification of schedule of increments of progress	Determined by Hearing Board	10 days minimum to APCO, air basin, district, ARB, EPA, and petitioner	1 Hearing Board member may hear if district population < 750,000, unless a public member objects
Interim authorization	30 day maximum	Reasonable notice to APCO and petitioner	No more than one granted application if modification of schedule. 1 H. B. member may hear if pop. < 750,000, unless a public member objects

400 - 34 June 1996

REGULATIONS

A variance provides a source temporary relief from enforcement action while steps are being taken by the source to bring itself back into compliance with the rule.

If it has been determined that a variance is necessary, a source then files a petition with a local air district. After the petition is properly noticed, a hearing is held. A variance can be granted provided specific findings of the H&SC can be made by the hearing board. The burden of proof and the presentation of findings to the board is on the petitioner (refer to H&SC 42352). The district staff most often assists the applicant with the petition and how to best present their case to the hearing board.

If a source applies for a short or regular variance and wishes to remain operating pending the decision and hearing on the regular or short application, it may apply for an interim variance. An interim variance is usually granted the same day it is applied for, and should expire on the date of the upcoming hearing. Emergency variances are granted for the breakdown condition described in #1 above. Emergency variances are also typically granted on the same day the petition is received.

It would be wise for a source to develop a compliance plan, to be presented to the hearing board as proof that they are on the road to compliance. The Air Resources Board recommends these plans for all variances; however, they are only required for a variance that exceeds a year. For help in developing such a plan, refer to H&SC 39051, which includes a typical schedule.

A source should be aware that the decision on whether to grant any variance rests with the district hearing board and not with the air pollution control officer or that person's staff. In general, the more information a source provides to the hearing board concerning its compliance problem, the better are its prospects of being granted a variance.

Rules for variance procedures vary somewhat from district to district. The district rules are based on H&SC statutes. Some of the applicable statutes are listed in Appendix B of this manual. District personnel as well as source operators should be familiar with these statutes and with the local district variance rule.

REGULATIONS

With regard to variances, State law (H&SC) requires that:

- 1. The district should not allow sources to operate in violation of district rules without a variance, even if the source is working towards finding a solution to the problem. Source operators should be aware that under H&SC Section 42400.2, if they continue to operate in violation of district rules, they are subject to a \$25,000 per day fine and up to 12 months in county jail.
- 2. All variance hearings should be noticed properly in accordance with H&SC Sections 40823 through 40827. Section 40826 requires a 30-day notice period for hearings for variances over a 90-day duration, except in small districts where there's a 15-day notice period for districts with a population under 750,000.
- 3. No variance shall be granted unless the hearing board makes all of the findings listed in H&SC, Section 42352. The burden of proof is on the petitioner to prove the findings at the hearing. District staff can give advice on how to best present the facts, but it is the petitioner's responsibility to present them.
- 4. No variance shall be granted if the granting of the variance is the result of source negligence, or if the variance will result in a nuisance.

ARB Recommendations

The Air Resources Board recommends that the following procedures be observed in the various stages involved from the time a source petitions for a variance through the end of the variance period. Some of these recommendations may not be a part of all districts' variance programs at this time; or, they may be written but not implemented procedures.

- 1. Parties petitioning for variance shall be required to fill out a petition form in writing.
- 2. The district will require sources to provide excess emissions figures on the petitions they submit. This information will be evaluated by the district staff. The emission figures are presented to the hearing board, so that the board formally recognizes, and the public may be aware of, the emissions impact of the variance. Excess emissions are an estimate of emissions. Any statements to abide by those estimates become an operating condition. Operating conditions shall be placed on the source, according to the H&SC.

REGULATIONS

- 3. An interim variance should be granted to only cover the time period needed to notice the petition for a regular variance and to render a decision on whether the variance is granted. This interim variance can subject the source to operating conditions during that interim period.
- 4. Variances should not be granted retroactively. The date that variance coverage begins cannot predate the date on which the petition was filed.
- 5. Each variance order will specify the equipment under variance and the district rule or regulation violated. By doing this, protection from enforcement action and the emissions resulting from granting the variance will be limited.
- 6. The district should schedule increments of progress for sources under variance, and should verify that the source is meeting these.
- 7. The district should require the source to quantify excess emissions that will occur during the period of variance, and to report these excess emissions according to a schedule.
- 8. At the end of the variance period, the district shall inspect the source to ensure that it is in compliance with all district air pollution regulations.

403.7 NEW SOURCE REVIEW RULES

Every district has a new source review rule which is intended to prevent the deterioration of air quality from new or modified sources with the least negative impact on economic growth. New source review rules are required as part of California's State Implementation Plan (SIP).

When a new source is constructed an Authority to Construct is required. This allows the district to calculate the emissions and make sure the source will comply with the new source review rule. The district will have a threshold of emissions that will require a new source to use Best Available Control Technology (BACT).

June 1996 400 - 37

REGULATIONS

403.7.1 BACT

BACT is the best emission control technology available while taking into account economic considerations. Each district has listings illustrating the BACT for every type of source including everything from gas turbines to automotive refinishing. All the California air districts base their BACT on the South Coast AQMD BACT. On the other hand, the emissions trigger level between different districts will vary widely. In the South Coast AQMD any increase in emissions from new equipment or a modification will require BACT, but in more rural district the level will be much higher (i.e. 25 pounds a day). Districts will also have different trigger levels for different pollutants.

The emissions trigger level depends on the designation of the district's air quality (moderate, serious, severe, and extreme). These designations depend mainly upon the concentration of ozone in the district (see Health and Safety Code 40918 to 40921).

403.7.2 Offsets

If emissions from a new or modified source are increased above the levels that require BACT, "offsets" may be required. The level at which offsets are triggered will also depend on the district's air quality designation. When offsets are triggered, the facility must decrease emissions in another area or offset them. This can be done by shutting down equipment, buying emission credits from another source, or by making changes to other equipment to reduce emissions.

400 - 38 June 1996

INSPECTION

Gas Turbines

501 INSPECTION

Sources are inspected in order to verify that a company's equipment is designed, installed, and operating in accordance with air pollution regulations and Permits to Operate. There are four ways that the compliance status of a source can be evaluated:

- 1. Engineering evaluations
- 2. Inspections
- 3. Source testing
- 4. Continuous emission monitoring

Of these, only the first and third provide actual emission data measurements from a facility. Inspections will primarily be the focus of this section, but source testing and continuous emission monitoring shall be briefly discussed.

One of the best ways a source can stay in compliance with air pollution regulations is through preventative maintenance inspections. Companies that have efficient inspection and maintenance (I&M) programs tend to have fewer breakdowns, require fewer variances, have less down time and can save money. With an efficient I & M program, problems with equipment can be anticipated and surprising catastrophic failures can be reduced. A good I & M program also requires that neat, orderly, consistent records of self-inspections be kept by the company. Local districts can usually assist sources with I & M programs.

Inspections of facilities may be performed for any one of the following reasons:

- 1. Compliance determination
- 2. Complaint investigation as a result of excess emissions or equipment malfunction
- 3. Source plan approval
- 4. Review or renewal of Permits
- 5. Special studies

Examples of special studies would be operating and maintenance evaluations, or updating emission inventories.

I&M

Reasons for Inspection

INSPECTION

Compliance-type inspections only provide preliminary emissions assessments. Source testing is the method of determining compliance with an emission standard. Compliance inspections are usually unannounced so that a facility can be evaluated under normal operating conditions.

For other inspections pertaining to source construction, plan approval, Permits to Operate, or "baseline type" inspections, the plant should be given sufficient advance notice so that qualified plant personnel can be present to provide the drawings, manuals, and process information that may be required. Prior notice should also be given when performing inspections for special studies designed to document operating and maintenance practices, or process and emission data. This will allow the operator time to make readily available information such as raw material rates, production levels, and stack test results. Regardless of the type of inspection to be conducted, pertinent supporting information should be obtained prior to, during, and following the source evaluation.

501.1 SEQUENCE OF INSPECTION

The sequence of an inspection is a question of what order to inspect the equipment in a system. The two main logical sequences to follow are a co-current flow and a counter-flow approach, but regardless of the type of sequence chosen, it is usually best to initially inspect the outside of a facility. By inspecting the perimeter of a plant an inspector can see if there are any illegal emissions or odors before the source is aware of an inspector's presence.

501.1.1 Co-Current Approach

The inspection of a facility using a co-current approach is conducting the inspection in the same general direction as the flow of the gas stream. The general sequence would be the process, the capture system, the control device, and the stack. An inspector may want to use this type of approach when he is unfamiliar with some process details.

INSPECTION

501.1.2 Counter-Flow Approach

An inspection with a counter-flow sequence is conducted against the direction of gas flow. An inspection of this type would generally begin at the stack and continue to the control device, capture system and then the process. The advantage of this approach is that an inspector may be able to more quickly identify where an emission problem originates.

501.1.3 Other Approaches

In some instances an inspector may not start with the stack of the process or the beginning or end of a system. If odors were detected outside the facility, an inspector may want to head directly to the source of the odor. If an inspector suspects illegal tampering with the control device equipment, he may head there directly. If an inspection is a strict, unannounced compliance-type, or if an inspector is very familiar with the process and only has a particular item to deal with, the inspection could start and finish in a different manner.

501.2 LEVELS OF INSPECTION

Four different levels of inspection have been developed by the U.S. EPA. These levels are classified as 1, 2, 3, or 4, where a level 1 inspection consists of an inspection that is the least in-depth and a level 4 inspection is the most in-depth. The levels are inclusive; a level 3 inspection, for example, would also include all the items done in a level 1 and level 2 inspection. Although these levels may not always be strictly adhered to in practice, the levels help organize all the means in which a system can be inspected.

Visible emissions evaluations are a part of level 1 inspections, and a survey of the plant boundary could be considered a part of a level 1 inspection. In a level 2 inspection an inspector conducts a walkthrough evaluation of the gas turbine and related equipment. All the data acquired in a level 2 inspection is acquired from on-site gauges. In a level 3 inspection, independent measurements of operating conditions separate from the existing on-site gauges are conducted. This is usually done when the existing on-site gauges are inadequate. A level 4 inspection is performed by agency supervisors or senior inspectors to acquire baseline data. As with the level 3 inspection, independent monitoring

June 1996 500 - 3

INSPECTION

whether or not there have been any problems in the past. Request a copy of applicable material safety data sheets (MSDS). A facility may have over a thousand of them since MSDSs exist for materials ranging from dishwashing soap to ammonia. If necessary discuss sampling procedures with the source representative.

The district's equipment list on the Permit to Operate should be compared to the facility's Permit to Operate. The items should be the same. If they are not, a Notice of Violation may have to be issued. Also, check existing Permit conditions and ask if any other changes have been made to the operation which are not reflected in the Permit.

503 GAS TURBINE INSPECTION

Inspectors can determine whether a gas turbine complies with air pollution regulations and Permits to Operate by obtaining operating information and comparing the data to limits on Permits. Source tests must be conducted to determine the gas turbine emissions, but items in this section discuss how an inspector can determine compliance.

503.1 GAS TURBINE VISIBLE EMISSIONS (ALL LEVELS)

Method 9

EPA Method 9 (Visual Determination of the Opacity of Emissions from Stationary Sources) is found in 40 CFR Ch. 1, Part 60. The method requires the recording of certain specific information in the field documentation of a visible emission observation. The required information includes the name of the plant, the emission location, the type of facility, the observer's name and affiliation, the date, the time, the estimated distance to the emission location, the approximate wind direction, the estimated wind speed, a description of the sky conditions, and the plume background, in addition to a minimum of 24 observations.

Health & Safety Code

In California the visible emission regulation is in Section 41701 of the California Health and Safety Code. The limit in the Health and Safety Code is a Ringelmann No. 2 or 40% opacity. The Ringelmann chart is a gray to black smoke scale, published by the United States Bureau of Mines, ranging from 0 to 5, where "0" is no visible smoke and "5" is totally black 100% opaque smoke (Table 403.9). In most districts the limit is Ringelmann No.1 or 20% opacity.

INSPECTION

Gas Turbines

White or colored smoke is measured by percent opacity. California provides that an aggregate of any of 13 or more readings (totalling more than 3 minutes) taken in a 1-hour period is a violation.

If possible, the visible emissions from the gas turbine stack should be observed before entering the facility. There should be little or no visible emissions coming from the stack. Only occasional faint wisps of smoke should be visible. If the emissions are over a Ringelmann 1 it is a violation in most districts. Permits may allow visible emissions during startup or shutdown of the gas turbine.

Another potential source of visible emissions violations is smoke from burning lubricating oil. The oil in the lubrication system, which is primarily for the bearings in the gas turbine, can get so hot that it may smoke. Some systems may even be equipped with filters to help prevent violations from the smoke.

Burning Lubricating Oil

503.2 GAS TURBINE GENERAL PHYSICAL CONDITIONS

As with most inspections, it is good to walk around the equipment at the plant, familiarize yourself with it, and look at the general condition of the equipment. On the other hand, much of the equipment at gas turbine power plants cannot be physically inspected, especially if it is running. Check for any signs of excessive corrosion or erosion. Look for cracked or worn ductwork expansion joints. It is unlikely that a gas turbine would have these types of problems, since they could be dangerous and inefficient, but these procedures are good to follow for most inspections.

503.3 GAS TURBINE FUELS

Gas turbines can burn a variety of fuels ranging from natural gas to distillate oil. Limits stated on the Permit may restrict what fuels can be used in the gas turbine. Permits may also require facilities to measure and record their fuel usage. Acquire a copy of the company's records showing the fuels used and the fuel usage since the last inspection. If any fuel was used that is not on the Permit, it is a violation.

June 1996 500 - 7

INSPECTION

It may be necessary to acquire a sample of the fuel to verify that it complies with the Permit. A major reason for sampling the fuel is to check the sulfur content. Permits may state the maximum allowable sulfur content of the fuel especially if it is distillate oil. An inspector should have facility personnel acquire samples, so they will not be libel for any damage to the equipment at the facility. Observe the person acquiring the sample to make sure it is gathered properly.

The storage of fuels for a gas turbine can be a potential source of emissions. Liquid petroleum fuels are kept in storage tanks. The inspection of storage tanks is included in the Petroleum Refining Technical Manual. In general, depending on the vapor pressure of the product in the tank, the tank and its pressure relief valves cannot leak hydrocarbon emissions. Floating roof tanks must also meet gap limits. Most gas turbines that run on liquid petroleum fuels use fuels with a low vapor pressure, such as diesel, which does not require vapor recovery or a gas tight tank. On the other hand, gas turbines can run on high vapor pressure fuels such as gasoline.

503.4 TIME OF OPERATION

A Permit may have conditions for a gas turbine that limit the hours of operation per year. Some facilities have peaking turbines that only run during heat waves in the summer months when energy demand is high. Gas turbines can also be used for emergency back-up power and these gas turbines often have limits on the time of operation. Acquire a copy of the facility's records showing the hours of operation since the last inspection. Compare the data to the requirements on the Permit and make sure the gas turbine operated for a period of time that is less than the maximum time allowed.

Startup and Shutdown

A Permit may describe the length of time for a startup and a shutdown period. A startup period may be a few of hours and a shutdown period is typically shorter in duration. Only one startup and shutdown period is usually allowed in one day. The Permit may allow a facility to exceed maximum emission concentrations stated on the Permit during startup and shutdown. On the other hand, the facility could still be accountable for these emissions on a daily or yearly basis.

INSPECTION

503.5 WATER OR STEAM INJECTION

If the water or steam injection rate is too low, NOx emissions will be too high. If the water or steam injection rate is too high, carbon monoxide and unburned hydrocarbon emissions will be higher. The injection rate is usually computed as the ratio of the mass of water or steam to mass of fuel. Permits may require facilities to measure and record the water or steam to fuel ratio. Acquire a copy of the plant's logs to verify water or steam injection rate requirements.

503.6 AMMONIA INJECTION AND SCR

The amount of ammonia injected for selective catalytic reduction is an important parameter. If enough ammonia is not injected there will be a lower amount of NOx removed, but if the ammonia injection is excessive, there will be an excessive ammonia slip. In extreme cases a large ammonia slip will cause a yellowish or brown plume. A bluish-white plume can also form under cold or humid conditions, due to the particle size distribution of nucleated ammonia compounds.

If a gas turbine power plant has SCR, the Permit will typically require that it operates, except during startup and shutdown, when the flue gases in the HRSG are above a specific temperature. This temperature is usually relatively low so that during normal operation it will easily be exceeded. Continuous monitoring and recording of the temperature at the catalyst or other locations in the HRSG will probably be required. Permit conditions will also usually state the maximum concentration of ammonia allowed in the stack gas and require the facility to keep track of ammonia usage. Acquire copies of the company's ammonia usage records. Obtain copies of chart recorder printouts and other necessary data.

503.7 CO CATALYST

Permits will often state that the carbon monoxide or oxidation catalyst must be installed and operating properly whenever the gas turbine is in operation. The facility may be exempt from this requirement during startup and shutdown.

Ammonia Plume

June 1996 500 - 9



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June 1996 A - 1

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A - 5

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- 43. U.S. EPA, <u>Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines</u>, (Research Triangle Park, NC: January 1993) p. 5-40.
- 44. Marvin M. Schorr, op. cit., p. 52. and U.S. EPA, Alternative Control Techniques Document, op. cit., p. 5-49.
- 45. U.S. EPA, Alternative Control Techniques Document, op. cit., p. 5-48.
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- 47. U.S. EPA, <u>Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines</u>, (Research Triangle Park, NC: January 1993) p. 5-60.
- 47.1 U.S. EPA, Alternative Control Techniques Document, op. cit., p. 5-82.
- 48. U.S. EPA, Alternative Control Techniques Document, op. cit., p. 5-80.
- 49. Stuart Birch, "Aircraft Engine Emission Reduction", <u>Aerospace Engineering</u>, (Jan/Feb 1994), p. 16.
- 50. Stuart Birch, op. cit., p. 17.

APPENDIX A

- 51. Stuart Birch, loc. cit.
- 52. U.S. EPA, Alternative Control Techniques Document, op. cit., p. 5-84.
- 53. U.S. EPA, Alternative Control Techniques Document, loc. cit.
- 54. U.S. EPA, Alternative Control Techniques Document, loc. cit.

Glossary

- 1. R.D. Lagenkamp, <u>Handbook of Oil Industry Terms and Phrases</u>, Third Edition, (Tulsa, Oklahoma: PennWell Publishing Company, 1981) p. 33.
- 2. R.D. Lagenkamp, op. cit., p. 46.
- 3. Michael R. Lindeburg, <u>Mechanical Engineering Reference Manual</u>, Eighth Edition, (Belmont, CA: Professional Publications, Inc., 1990) p. 6-7.
- 4. Paul W. Gill, James H. Smith Jr., Eugene J. Ziurys, <u>Internal Combustion Engines</u>, Fourth Edition (Tulsa, Oklahoma: PennWell Publishing Company, 1959) p. 16-42.
- 5. Paul W. Gill, James H. Smith Jr., Eugene J. Ziurys, loc. cit.
- 6. Paul W. Gill, James H. Smith Jr., Eugene J. Ziurys, loc. cit.

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APPENDIX B

CALIFORNIA HEALTH AND SAFETY CODE (H&SC)

The following sections of the California Health and Safety Code listed below have been selected for verbatim presentation. These H&SC sections are the basis for air pollution control laws, including the authority of districts to adopt and enforce regulations, to perform inspections, and to issue permits with conditions. (For specific situations, you may wish to consult the complete H&SC.)

39000	Legislative Findings - Environment
39001	Legislative Findings - Agency Coordination
39002	Local and State Agency Responsibilities
39003	ARB Responsibilities
40000	Local / State Responsibilities
40001	Adoption and Enforcement of Rules and Regulations
40702	Adoption of Rules and Regulations
41509	No Limitation on Power to Abate Nuisance
41510	Right of Entry With Inspection Warrant
41700	No Person Shall Discharge Pollutants
41701	Opacity Standards - No Emissions Shall Exceed Ringelmann 2
42300	District Permit System
42301	Permit Issuance - Requirements
42301.6	Permit Approval: Powers and Duties of Air Pollution Control Officer
42301.7	Air Contaminants, Threatened Release
42303	Information Disclosure - Air Contaminant Discharge
42303.5	False Statements in Permit Applications
42304	Permit Suspension (Failure to Supply Information)
42352	Variance - Findings Required for Issuance
42400	Penalties, Criminal - Misdemeanor, \$1,000/Day and/or Six Months Jail
42400.1	Penalties, Criminal - Negligence, \$15,000/Day and/or Nine Months Jail
	Penalties, Criminal - Knowingly, \$25,000/Day and/or One Year Jail
42400.3	Penalties, Criminal - Willfully \$50,000/Day and/or One Year Jail
42401	Penalties, Civil - Violating Order of Abatement \$25,000/Day
42402	Penalties, Civil - Violations \$1,000/Day
42402.1	Penalties, Civil - Negligence, \$15,000/Day
42402.2	Penalties, Civil - Knowingly, \$25,000/Day
	Penalties, Civil - Willfully \$50,000/Day
42402.5	Penalties, Civil - Administrative, \$500/Each Violation
42403	Penalties, Civil - Relevant Circumstances
	Statute of Limitations for Civil Actions
42450	Orders of Abatement, District Board: Authority, Notice, Hearing

H&SC Sections List

June 1996

APPENDIX B

HEALTH AND SAFETY CODE, INTRODUCTION

The California Legislature passes laws, called statutes, that authorize Executive branch agencies (such as the Air Resources Board) to implement laws, through regulations, pursuant to the directives of the statutes.

The following relevant California H&SC references are included verbatim to provide you with the basis for California Air Pollution Control Laws. The paragraph numbers are the H&SC Section numbers in numerical order:

39000 LEGISLATIVE FINDINGS - ENVIRONMENT

H&SC Sections in Numerical Order The Legislature finds and declares that the people of the State of California have a primary interest in the quality of the physical environment in which they live, and that this physical environment is being degraded by the waste and refuse of civilization polluting the atmosphere, thereby creating a situation which is detrimental to the health, safety, welfare, and sense of well-being of the people of California.

39001 LEGISLATIVE FINDINGS - AGENCY COORDINATION

The Legislature, therefore, declares that this public interest shall be safeguarded by an intensive, coordinated state, regional, and local effort to protect and enhance the ambient air quality of the state. Since air pollution knows no political boundaries, the Legislature declares that a regional approach to the problem should be encouraged whenever possible and, to this end, the state is divided into air basins. The state should provide incentives for such regional strategies, respecting, when necessary, existing political boundaries.

39002 LOCAL AND STATE AGENCY RESPONSIBILITIES

Local and regional authorities have the primary responsibility for control of air pollution from all sources other than vehicular sources. The control of vehicular sources, except as otherwise provided in this division, shall be the responsibility of the State Air Resources Board. Except as otherwise provided in this division, including, but not limited to, Sections 41809, 41810, and 41904, local and regional authorities may establish stricter standards than those set by law or by the state board for nonvehicular sources. However, the state board shall, after holding public hearings as required in this division, undertake control activities

APPENDIX B

in any area wherein it determines that the local or regional authority has failed to meet the responsibilities given to it by this division or by any other provision of law.

39003 ARB RESPONSIBILITIES

The State Air Resources Board is the state agency charged with coordinating efforts to attain and maintain ambient air quality standards, to conduct research into the causes of and solution to air pollution, and to systematically attack the serious problem caused by motor vehicles, which is the major source of air pollution in many areas of the state.

40000 LOCAL / STATE RESPONSIBILITIES

The Legislature finds and declares that local and regional authorities have the primary responsibility for control of air pollution from all sources, other than emissions from motor vehicles. The control of emissions from motor vehicles, except as otherwise provided in this division, shall be the responsibility of the state board.

40001 ADOPTION & ENFORCEMENT OF RULES / REGULATIONS

- (a) Subject to the powers and duties of the state board, the districts shall adopt and enforce rules and regulations to achieve and maintain the state and federal ambient air quality standards in all areas affected by emission sources under their jurisdiction, and shall enforce all applicable provisions of state and federal law
- (b) The rules and regulations may, and at the request of the state board shall, provide for the prevention and abatement of air pollution episodes which, at intervals, cause discomfort or health risks to, or damage to property of, a significant number of persons or class of persons.
- (c) Prior to adopting any rule or regulation to reduce criteria pollutants, a district shall determine that there is a problem that the proposed rule or regulation will alleviate and that the rule or regulation will promote the attainment or maintenance of state or federal ambient air quality standards.

Prevent and Abate Episodes

June 1996

APPENDIX B

40702 ADOPTION OF RULES AND REGULATIONS

A district shall adopt rules and regulations and do such acts as may be necessary or proper to execute the powers and duties granted to, and imposed upon, the district by this division and other statutory provisions. No order, rule, or regulation of any district shall, however, specify the design of equipment, type of construction, or particular method to be used in reducing the release of air contaminants from railroad locomotives.

41509 NO LIMITATION ON POWER TO ABATE NUISANCE

No provision of this division, or of any order, rule, or regulation of the state board or of any district, is a limitation on:

- (a) The power of any local or regional authority to declare, prohibit, or abate nuisances.
- (b) The power of the Attorney General, at the request of a local or regional authority, the state board, or upon his own motion, to bring an action in the name of the people of the State of California to enjoin any pollution or nuisance.
- (c) The power of a state agency in the enforcement or administration of any provision of law which it is specifically permitted or required to enforce or administer.
- (d) The right of any person to maintain at any time any appropriate action for relief against any private nuisance.

41510 RIGHT OF ENTRY WITH INSPECTION WARRANT

Right of Entry

For the purpose of enforcing or administering any state or local law, order, regulation, or rule relating to air pollution, the executive officer of the state board or any air pollution control officer having jurisdiction, or an authorized representative of such officer, upon presentation of his credentials or, if necessary under the circumstances, after obtaining an inspection warrant pursuant to Title 13 (commencing with Section 1822.50), Part 3 of the Code of Civil Procedure, shall have the right of entry to any premises on which an air pollution emission source is located for the purpose of inspecting such source, including

APPENDIX B

Gas Turbines

securing samples of emissions therefrom, or any records required to be maintained in connection therewith by the state board or any district.

41700 NO PERSON SHALL DISCHARGE POLLUTANTS

Except as otherwise provided in Section 41705, no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property.

41701 OPACITY STANDARDS - NO EMISSIONS SHALL EXCEED RINGELMANN 2

Except as otherwise provided in Section 41704, or Article 2 (commencing with Section 41800) of this chapter other than Section 41812, or Article 2 (commencing with Section 42350) of Chapter 4, no person shall discharge into the atmosphere from any source whatsoever any air contaminant, other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour which is:

- (a) As dark or darker in shade as that designated as No. 2 on the Ringelmann Chart, as published by the United States Bureau of Mines, or
- (b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subdivision (a).

42300 DISTRICT PERMIT SYSTEM

- (a) Every district board may establish, by regulation, a permit system that requires, except as otherwise provided in Section 42310, that before any person builds, erects, alters, replaces, operates, or uses any article, machine, equipment, or other contrivance which may cause the issuance of air contaminants, the person obtain a permit to do so from the air pollution control officer of the district.
- (b) The regulations may provide that a permit shall be valid only for a specified period. However, the expiration date of any permit shall be extended upon

Opacity

APPENDIX B

completion of the annual review required pursuant to subdivision (e) of Section 42301 and payment of the fees required pursuant to Section 42311, unless the air pollution control officer or the hearing board has initiated action to suspend or revoke the permit pursuant to Section 42304, 42307, or 42390, that action has resulted in a final determination by the officer or the board to suspend or revoke the permit, and all appeals have been exhausted or the time for appeals from that final determination has been exhausted.

(c) The annual extension of a permit's expiration date pursuant to subdivision (b) does not constitute permit issuance, renewal, reopening, amendment, or any other action subject to the requirements specified in Title V.

42301 PERMIT ISSUANCE - REQUIREMENTS

Permit System Shall Do . . .

A permit system established pursuant to Section 42300 shall do all of the following:

- (a) Ensure that the article, machine, equipment, or contrivance for which the permit was issued does not prevent or interfere with the attainment or maintenance of any applicable air quality standard.
- (b) Prohibit the issuance of a permit unless the air pollution control officer is satisfied, on the basis of criteria adopted by the district board, that the article, machine, equipment, or contrivance will comply with all of the following:
 - (1) All applicable orders, rules, and regulations of the district and of the state board.
 - (2) All applicable provisions of this division.
- (c) Prohibit the issuance of a permit to a Title V source if the Administrator of the Environmental Protection Agency objects to its issuance in a timely manner as provided in Title V. This subdivision is not intended to provide any authority to the Environmental Protection Agency to object to the issuance of a permit other than that authority expressly granted by Title V.
- (d) Provide that the air pollution control officer may issue to a Title V source a permit to operate or use if the owner or operator of the Title V source presents a variance exempting the owner or operator from Section 41701, any rule or regulation of the district, or any permit condition imposed pursuant to this

APPENDIX B

section, or presents an abatement order that has the effect of a variance and that meets all of the requirements of this part pertaining to variances, and the requirements for the issuance of permits to operate are otherwise satisfied. The terms and conditions of any variance or abatement order may be incorporated into the permit as a compliance schedule, to the extent required by Title V.

- (e) Require, upon annual renewal, that each permit be reviewed to determine that the permit conditions are adequate to ensure compliance with, and the enforceability of, district rules and regulations applicable to the article, machine, equipment, or contrivance for which the permit was issued which were in effect at the time the permit was issued or modified, or which have subsequently been adopted and made retroactively applicable to an existing article, machine, equipment, or contrivance, by the district board and, if the permit conditions are not consistent, require that the permit be revised to specify the permit conditions in accordance with all applicable rules and regulations.
- (f) Provide for the reissuance or transfer of a permit to a new owner or operator of an article, machine, equipment, or contrivance. An application for transfer of ownership only, or change in operator only, of any article, machine, equipment, or contrivance which had a valid permit to operate within the two-year period immediately preceding the application is a temporary permit to operate. Issuance of the final permit to operate shall be conditional upon a determination by the district that the criteria specified in subdivisions (b) and (e) are met, if the permit was not surrendered as a condition to receiving emission reduction credits pursuant to banking or permitting rules of the district. However, under no circumstances shall the criteria specify that a change of ownership or operator alone is a basis for requiring more stringent emission controls or operating conditions than would otherwise apply to the article, machine, equipment, or contrivance.

42301.6 PERMIT APPROVAL: POWERS AND DUTIES OF AIR POLLUTION CONTROL OFFICER

(a) Prior to approving an application for a permit to construct or modify a source which emits hazardous air emissions, which source is located within 1,000 feet from the outer boundary of a schoolsite, the air pollution control officer shall prepare a public notice in which the proposed project or modification for which the application for a permit is made is fully described. The notice may be prepared whether or not the material is or would be subject to subdivi-

Near a **Schoolsite**

APPENDIX B

- (2) If the facility has not filed a risk management and prevention plan with the administering agency, require the preparation and submission of a plan to the administering agency pursuant to Section 25534. Notwithstanding any other provision of law, the administering agency may require the filing of a risk management and prevention plan and its implementation at the earliest feasible date.
- (c) The air pollution control officer may, in responding to a reasonably fore-seeable threat of a release, do any of the following:
- (1) If necessary, issue an immediate order to prevent the release or mitigate the reasonably foreseeable threat of a release in violation of Section 41700 pending a hearing pursuant to Section 42450 when there is a substantial probability of an injury to persons at a school resulting from a release that makes it reasonably necessary to take immediate action to prevent, reduce, or mitigate that injury. The officer may not issue such an order unless there is written concurrence to issue the order by a representative of the administering agency.
- (2) Apply to the district board for issuance of an order for abatement pursuant to Section 42450.
 - (d) Nothing in this section limits any existing authority of any district.

42303 INFORMATION DISCLOSURE - AIR CONTAMINANT DISCHARGE

An air pollution control officer, at any time, may require from an applicant for, or the holder of, any permit provided for by the regulations of the district board, such information, analyses, plans, or specifications which will disclose the nature, extent, quantity, or degree of air contaminants which are, or may be, discharged by the source for which the permit was issued or applied.

42303.5 FALSE STATEMENTS IN PERMIT APPLICATIONS

No person shall knowingly make any false statement in any application for a permit, or in any information, analyses, plans, or specifications submitted in conjunction with the application or at the request of the air pollution control officer.

Prevent, Reduce, Mitigate Injury

APPENDIX B

Gas Turbines

42304 PERMIT SUSPENSION (FAILURE TO SUPPLY INFORMATION)

If, within a reasonable time, the holder of any permit issued by a district board willfully fails and refuses to furnish the information, analyses, plans, or specifications requested by the district air pollution control officer, such officer may suspend the permit. Such officer shall serve notice in writing of such suspension and the reasons therefor on the permittee.

42352 VARIANCE - FINDINGS REQUIRED FOR ISSUANCE

- (a) No variance shall be granted unless the hearing board makes all of the following findings:
- (1) That the petitioner for a variance is, or will be, in violation of Section 41701 or of any rule, regulation, or order of the district.
- (2) That, due to conditions beyond the reasonable control of the petitioner, requiring compliance would result in either (A) an arbitrary or unreasonable taking of property, or (B) the practical closing and elimination of a lawful business. In making those findings where the petitioner is a public agency, the hearing board shall consider whether or not requiring immediate compliance would impose an unreasonable burden upon an essential public service. For purposes of this paragraph, "essential public service" means a prison, detention facility, police or firefighting facility, school, health care facility, landfill gas control or processing facility, sewage treatment works, or water delivery operation, if owned and operated by a public agency.
- (3) That the closing or taking would be without a corresponding benefit in reducing air contaminants.
- (4) That the applicant for the variance has given consideration to curtailing operations of the source in lieu of obtaining a variance.
- (5) During the period the variance is in effect, that the applicant will reduce excess emissions to the maximum extent feasible.
- (6) During the period the variance is in effect, that the applicant will monitor or otherwise quantify emission levels from the source, if requested to do so by the district, and report these emission levels to the district pursuant to a schedule established by the district.
- (b) As used in this section, "public agency" means any state agency, board, or commission, any county, city and county, city, regional agency, public district,

Variance Conditions

Essential Public Service

APPENDIX B

or other political subdivision. [Further stipulations of Subsection 42352.5 are not included in this technical manual.]

42400 PENALTIES, CRIMINAL - MISDEMEANOR

- (a) Except as otherwise provided in Section 42400.1, 42400.2, or 42400.3, any person who violates this part, or any rule, regulation, permit, or order of the state board or of a district, including a district hearing board, adopted pursuant to Part 1 (commencing with Section 39000) to Part 4 (commencing with Section 41500), inclusive, is guilty of a misdemeanor and is subject to a fine of not more than one thousand dollars (\$1,000) or imprisonment in the county jail for not more than six months, or both.
- (b) If a violation under subdivision (a) with regard to the failure to operate a vapor recovery system on a gasoline cargo tank is directly caused by the actions of an employee under the supervision of, or of any independent contractor working for, any person subject to this part, the employee or independent contractor, as the case may be, causing the violation is guilty of a misdemeanor and is punishable as provided in subdivision (a). That liability shall not extend to the person employing the employee or retaining the independent contractor, unless that person is separately guilty of an action that violates this part.
- (c) The recovery of civil penalties pursuant to Section 42402, 42402.1, 42402.2, or 42402.3 precludes prosecution pursuant to this section for the same offense. When a district refers a violation to a prosecuting agency, the filing of a criminal complaint is grounds requiring the dismissal of any civil action brought pursuant to this article for the same offense.

Each Day a Separate Offense

(d) Each day during any portion of which a violation of subdivision (a) occurs is a separate offense.

42400.1 PENALTIES, CRIMINAL - NEGLIGENCE

(a) Any person who negligently emits an air contaminant in violation of any provision of this part or any rule, regulation, permit, or order of the state board or of a district pertaining to emission regulations or limitations is guilty of a misdemeanor and is subject to a fine of not more than fifteen thousand dollars (\$15,000) or imprisonment in the county jail for not more than nine months, or both.

- (b) Any person who owns or operates any source of air contaminants in violation of Section 41700 which causes actual injury, as defined in paragraph (2) of subdivision (d) of Section 42400.2, to the health or safety of a considerable number of persons or the public is guilty of a misdemeanor and is punishable as provided in subdivision (a).
- (c) Each day during any portion of which a violation occurs is a separate offense.
- (d) The recovery of civil penalties pursuant to Section 42402, 42402.1, 42402.2, or 42402.3 precludes prosecution pursuant to this section for the same offense. When a district refers a violation to a prosecuting agency, the filing of a criminal complaint is grounds requiring the dismissal of any civil action brought pursuant to this article for the same offense.

42400.2 PENALTIES, CRIMINAL - KNOWINGLY, DOCUMENT FALSIFICATION / FAILURE TO TAKE CORRECTIVE ACTION

- (a) Any person who emits an air contaminant in violation of any provision of this part, or any order, rule, regulation, or permit of the state board or of a district pertaining to emission regulations or limitations, and who knew of the emission and failed to take corrective action within a reasonable period of time under the circumstances, is guilty of a misdemeanor and is subject to a fine of not more than twenty-five thousand dollars (\$25,000) or imprisonment in the county jail for not more than one year, or both.
- (b) For purposes of this section, "corrective action" means the termination of the emission violation or the grant of a variance from the applicable order, rule, regulation, or permit pursuant to Article 2 (commencing with Section 42350). If a district regulation regarding process upsets or equipment breakdowns would allow continued operation of equipment which is emitting air contaminants in excess of allowable limits, compliance with that regulation is deemed to be corrective action.
- (c) Any person who, knowingly and with intent to deceive, falsifies any document required to be kept pursuant to any provision of this part, or any rule, regulation, permit, or order of the state board or of a district, is guilty of a misdemeanor and is punishable as provided in subdivision (a).

Corrective Action

APPENDIX B

- (d) (1) Any person who owns or operates any source of air contaminants in violation of Section 41700 which causes actual injury to the health or safety of a considerable number of persons or the public, and who knew of the emission and failed to take corrective action within a reasonable period of time under the circumstances, is guilty of a misdemeanor and is punishable as provided in subdivision (a).
- (2) As used in this subdivision, "actual injury" means any physical injury which, in the opinion of a licensed physician and surgeon, requires medical treatment involving more than a physical examination.
- (e) Each day during any portion of which a violation occurs constitutes a separate offense.
- (f) The recovery of civil penalties pursuant to Section 42402, 42402.1, 42402.2, or 42402.3 precludes prosecution pursuant to this section for the same offense. When a district refers a violation to a prosecuting agency, the filing of a criminal complaint is grounds requiring the dismissal of any civil action brought pursuant to this article for the same offense.

42400.3 PENALTIES, CRIMINAL - WILLFULLY, INTENTIONALLY

- (a) Any person who willfully and intentionally emits an air contaminant in violation of any provision of this part or any rule, regulation, permit, or order of the state board or of a district, pertaining to emission regulations or limitations is guilty of a misdemeanor and is subject to a fine of not more than fifty thousand dollars (\$50,000) or imprisonment in the county jail for not more than one year, or both.
- (b) The recovery of civil penalties pursuant to Section 42402, 42402.1, 42402.2, or 42402.3 precludes prosecution pursuant to this section for the same offense. When a district refers a violation to a prosecuting agency, the filing of a criminal complaint is grounds requiring the dismissal of any civil action brought pursuant to this article for the same offense.
- (c) Each day during any portion of which a violation occurs constitutes a separate offense.

APPENDIX B

42401 PENALTIES, CIVIL - VIOLATING ORDER OF ABATEMENT

Any person who intentionally or negligently violates any order of abatement issued by a district pursuant to Section 42450, by a hearing board pursuant to Section 42451, or by the state board pursuant to Section 41505 is liable for a civil penalty of not more than twenty-five thousand dollars (\$25,000) for each day in which the violation occurs.

42402 PENALTIES, CIVIL - GENERAL VIOLATIONS

- (a) Except as otherwise provided in subdivision (b) or in Section 42402.1, 42402.2, or 42402.3, any person who violates this part, any order issued pursuant to Section 42316, or any rule, regulation, permit, or order of a district, including a district hearing board, or of the state board issued pursuant to Part 1 (commencing with Section 39000) to Part 4 (commencing with Section 41500), inclusive, is strictly liable for a civil penalty of not more than one thousand dollars (\$1,000).
- (b) (1) Any person who violates any provision of this part, any order issued pursuant to Section 42316, or any rule, regulation, permit, or order of a district, including a district hearing board, or of the state board issued pursuant to Part 1 (commencing with Section 39000) to Part 4 (commencing with Section 41500), inclusive, is strictly liable for a civil penalty of not more than ten thousand dollars (\$10,000).
- (2) Where a civil penalty in excess of one thousand dollars (\$1,000) for each day in which the violation occurs is sought, there is no liability under this subdivision if the person accused of the violation alleges by affirmative defense and establishes that the violation was caused by an act which was not the result of intentional or negligent conduct. In a district in which a Title V permit program has been fully approved, this paragraph shall not apply to a violation of federally enforceable requirements that occurs at a Title V source.
- (c) Each day during any portion of which a violation occurs is a separate offense.

42402.1 PENALTIES, CIVIL - NEGLIGENCE OR ACTUAL INJURY

(a) Any person who negligently emits an air contaminant in violation of this part or any rule, regulation, permit, or order of the state board or of a district

APPENDIX B

pertaining to emission regulations or limitations is liable for a civil penalty of not more than fifteen thousand dollars (\$15,000).

Owner or Operator is Liable

- (b) Any person who owns or operates any source of air contaminants in violation of Section 41700 which causes actual injury, as defined in paragraph (2) of subdivision (d) of Section 42400.2, to the health or safety of a considerable number of persons or the public is liable for a civil penalty as provided in subdivision (a).
- (c) Each day during any portion of which a violation occurs is a separate offense.

42402.2 PENALTIES, CIVIL - KNOWINGLY, DOCUMENT FALSIFICATION, FAILURE TO TAKE CORRECTIVE ACTION

- (a) Any person who emits an air contaminant in violation of any provision of this part, or any order, rule, regulation, or permit of the state board or of a district pertaining to emission regulations or limitations, and who knew of the emission and failed to take corrective action, as defined in subdivision (b) of Section 42400.2, within a reasonable period of time under the circumstances, is liable for a civil penalty, of not more than twenty-five thousand dollars (\$25,000).
- (b) Any person who, knowingly and with intent to deceive, falsifies any document required to be kept pursuant to any provision of this part, or any rule, regulation, permit, or order of the state board or of a district, is subject to the same civil penalty as provided in subdivision (a).
- (c) Any person who owns or operates any source of air contaminants in violation of Section 41700 which causes actual injury, as defined in paragraph (2) of subdivision (d) of Section 42400.2, to the health or safety of a considerable number of persons or the public, and who knew of the emission and failed to take corrective action, as defined in subdivision (b) of Section 42400.2, within a reasonable period of time under the circumstances, is subject to a civil penalty as provided in subdivision (a).
- (d) Each day during any portion of which a violation occurs is a separate offense.

APPENDIX B

42402.3 PENALTIES, CIVIL - WILLFULLY AND INTENTIONALLY

- (a) Any person who willfully and intentionally emits an air contaminant in violation of this part or any rule, regulation, permit, or order of the state board, or of a district, pertaining to emission regulations or limitations, is liable for a civil penalty of not more than fifty thousand dollars (\$50,000).
- (b) Each day during any portion of which a violation occurs is a separate offense.

42402.5 PENALTIES, CIVIL - ADMINISTRATIVE

In addition to any civil and criminal penalties prescribed under this article, a district may impose administrative civil penalties for a violation of this part, or any order, permit, rule, or regulation of the state board or of a district, including a district hearing board, adopted pursuant to Part 1 (commencing with Section 39000) to Part 4 (commencing with Section 41500), inclusive, if the district board has adopted rules and regulations specifying procedures for the imposition and amounts of these penalties. No administrative civil penalty levied pursuant to this section may exceed five hundred dollars (\$500) for each violation. However, nothing in this section is intended to restrict the authority of a district to negotiate mutual settlements under any other penalty provisions of law which exceeds five hundred dollars (\$500).

42403 PENALTIES, CIVIL - RELEVANT CIRCUMSTANCES

- (a) The civil penalties prescribed in Sections 39674, 42401, 42402, 42402.1, 42402.2, and 42402.3 shall be assessed and recovered in a civil action brought in the name of the people of the State of California by the Attorney General, by any district attorney, or by the attorney for any district in which the violation occurs in any court of competent jurisdiction.
- (b) In determining the amount assessed, the court, or in reaching any settlement, the district, shall take into consideration all relevant circumstances, including, but not limited to, the following:
 - (1) The extent of harm caused by the violation.
 - (2) The nature and persistence of the violation.
 - (3) The length of time over which the violation occurs.

Civil Penalties May Depend On . . .

APPENDIX B

- (4) The frequency of past violations.
- (5) The record of maintenance.
- (6) The unproven or innovative nature of the control equipment.
- (7) Any action taken by the defendant, including the nature, extent, and time of response of the cleanup and construction undertaken, to mitigate the violation.
 - (8) The financial burden to the defendant.

42404.5 STATUTE OF LIMITATIONS FOR CIVIL ACTIONS

Any limitation of time applicable to actions brought pursuant to Section 42403 shall not commence to run until the offense has been discovered, or could reasonably have been discovered.

42450 ORDERS OF ABATEMENT, DISTRICT BOARD: AUTHORITY, NOTICE AND HEARING

The district board may, after notice and a hearing, issue an order for abatement whenever it finds that any person is constructing or operating any article, machine, equipment, or other contrivance without a permit required by this part, or is in violation of Section 41700 or 41701 or of any order, rule, or regulation prohibiting or limiting the discharge of air contaminants into the air.

In holding such a hearing, the district board shall be vested with all the powers and duties of the hearing board. Notice shall be given, and the hearing shall be held, pursuant to Chapter 8 (commencing with Section 40800) of Part 3.

GLOSSARY

Adiabatic - A process where there is no heat transfer.

Aero-Derivative Gas Turbine - A stationary gas turbine that was originally designed to operate as an aircraft engine.

Afterburner - An extended section on the end of a turbojet engine that behaves as a second combustion chamber. Fuel is sprayed into the section and ignited. The afterburner increases the thrust produced by the engine.

Airfoil - A curved surface, typically similar to the shape of a wing on an airplane. Compressor and turbine blades have an airfoil shape.

Air Rate - A parameter that describes the size of a gas turbine. The air rate is the mass flow rate of air through the gas turbine divided by the horsepower output. The units of air rate are lbm/hp-hr.

Alveoli - Small air sacs in the lungs where gas exchange of carbon dioxide and oxygen between the air and the blood takes place.

Ammonia (NH₃) - A hazardous substance (Title III, Section 302, SARA) that is usually used in selective catalytic reduction to remove NOx compounds. It is injected into the flue gas before it flows through the selective catalytic reduction catalyst in the heat recovery steam generator of a gas turbine. Ammonia is also injected into other combustion processes to reduce NOx.

Ammonia bisulfate - An ammonia salt that forms from ammonia and sulfur trioxide (SO₃). It is a sticky substance that can foul and corrode boiler tubes.

Ammonia sulfate - An ammonia salt that forms from ammonia and sulfur trioxide (SO₃). It is a substance that can foul boiler tubes, but it is not corrosive like ammonia bisulfate.

Ammonia Slip - The unavoidable emissions of ammonia from the stack of a selective catalytic reduction unit. Excess ammonia is required for SCR since mixing is not perfect. Excess and unreacted ammonia becomes the ammonia slip.

June 1996 Gloss - 1

GLOSSARY

Annular Combustor - A combustor with an annular shaped combustion chamber. The annular combustor fits across the entire diameter of the engine and the igniters are spaced evenly around the circumference of the combustion chamber.

Authority to Construct - A document given by an air pollution control district to permit a company to build or modify pollution generating or control equipment.

Axial Compressor - The type of compressor used in most modern gas turbines. It has a series of stages of rotating rotor blades and stationary stator blades. The stator blades are fixed to the casing of the compressor. The annular space which the air flows through decreases from front to back.

Axial Turbine - A turbine that is analogous to an axial compressor in that it is equipped with stages of rotor blades and stationary stator blades. The stator blades are fixed to the casing surrounding the turbine. Unlike the axial compressor, the annular space in an axial turbine increases from front to back.

Best Available Control Technology (BACT) - An emission limitation based on the maximum degree of emission reduction which (considering energy, environmental, and economic impacts and other costs) is achievable through application of production processes and available methods, systems, and techniques. In no event does BACT permit emissions in excess of those allowed under any applicable NSPS or NESHAP. It is applicable on a case-by-case basis for each major new (or modified) emission source to be located in areas attaining the National Ambient Air Quality Standards. It applies to each pollutant regulated under the Federal Clean Air Act, and is concerned with Prevention of Significant Deterioration (PSD).

Brayton Cycle - The theoretical combustion cycle of a gas turbine. The basic parts of the cycle include compression in a compressor, heat addition in a combustor, expansion in a turbine, and rejection of heat to the atmosphere. Under ideal or theoretical conditions, the compression and expansion occur with constant entropy and the heat addition and rejection have no pressure losses.

Butane (C_4H_{10}) - A hydrocarbon derived from crude petroleum that is gaseous at atmospheric conditions but it is easy to liquefy. It is the lightest hydrocarbon in gasoline.

GLOSSARY

California Health and Safety Code (CH&SC or H&SC) - A publication consisting of the state laws and statutes for air pollution control in California.

Can-Annular Combustor - A combustor that is designed as a cross between a can type combustor and an annular combustor. A can-annular combustor has separate cylindrically shaped combustion cans within an annular chamber.

Can Combustor - A combustor with a cylindrical, can-like shape. The can combustors are typically mounted around the circumference of the gas turbine.

Cantilever Turbine - A type of radial-flow turbine where gases are directed radially inward before entering the turbine.

Carbon Dioxide (CO₂) - A gaseous product of combustion. Carbon dioxide is not considered to be a pollutant, but it is a greenhouse gas.

Carbon Monoxide (CO) - A combustion product formed from incomplete combustion. It is a pollutant that forms when there is not enough oxygen or too much fuel in a combustion process. When inhaled, CO attaches more easily to hemoglobin than does oxygen, reducing the amount of oxygen reaching the body's cells.

Catalyst - A substance that hastens or retards a chemical reaction without being changed by the chemical reaction itself.¹

Centrifugal Compressor - Compressors that use centrifugal force to compress air. Air enters the impeller parallel to the axis of rotation and exits radially.

Closed Cycle Gas Turbine - A gas turbine where the working fluid is continually recirculated. A closed gas turbine cycle is not open to the atmosphere.

Cogeneration - A power plant or engine that produces mechanical work or electricity and steam or hot water. The steam/hot water is sent to another thermal process.

GLOSSARY

Combined Cycle Gas Turbine - A gas turbine power plant that not only produces electrical or mechanical energy from the gas turbine, but also uses the hot exhaust gases to produce steam. The steam can be used to make more electrical energy or to do mechanical work.

Combustion Liner - A shell-like device with holes in it that allows air to flow through into the inner portion of the combustion chamber where combustion occurs.

Combustor - The combustion chamber for a gas turbine, where the air and fuel enter and are ignited by igniter plugs. The main types of combustors are the can type, annular type, can-annular type, and the silo type.

Compression Ratio - The volume of a cylinder at bottom-dead-center divided by the volume of the cylinder at top-dead-center in a reciprocating internal combustion engine.

Compressor - A device used to increase the pressure of air entering a gas turbine. The main types of compressors used in gas turbines include centrifugal flow and axial flow. Most of the compressors used for gas turbines are the axial flow type.

Condenser - A vessel in a steam power plant used to condense steam that has been expanded through a steam turbine. The condensate from the condenser is then pumped back into the boiler to produce more steam.

Continuous Emission Monitor - A device that continually measures pollution emissions or process parameters from an operation, engine, or other device. The emissions may be printed on a chart recorder. Carbon monoxide, sulfur dioxide and nitrogen oxides are pollutants often measured in stacks of gas turbines by continuous emission monitors.

Cooling Tower - A large louvered device over which water flows to cool and aerate the water. Although most cooling towers are rectangular in shape, some are cylindrical.² As water flows down the device over the louvers, air is pulled upward. Some of the water evaporates and a water vapor plume may be seen emanating from the stack of the device. The water is cooled by the evaporation process.

Crude Oil - Petroleum that has not been refined. Oil as it comes from an oil well.

Deaerator - A direct contact heat exchanger where water is heated (usually by steam) to remove corrosive gases from the water. Oxygen is the main corrosive gas removed.

Diesel Cycle - The theoretical combustion cycle of the compression ignition engine. Diesel engines use the heat from compression for combustion; they do not have spark plugs. The parts of the cycle include adiabatic (no heat transfer) compression (in the cylinder from a piston), constant pressure heat addition (combustion), adiabatic expansion (work done on the piston) and constant volume heat rejection to the atmosphere.

Diesel Fuel - A refined petroleum product made from petroleum in the light gas oil range. Gas oil has a boiling point between 450 and 800°F and is heavier than hydrocarbons in the kerosene range.

Dry Bulb Temperature - The temperature of moist, still air. It is usually used as measurement of atmospheric conditions.

Dual Cycle - A theoretical combustion cycle that is a combination of the Otto Cycle (spark ignition engine) and the diesel cycle (compression ignition engine).

Duct Burner - A burner, located in the heat recovery steam generator of the gas turbine power plant, that heats the gas turbine exhaust. The duct burner increases the steam production of the plant.

Economizer - A heat exchanger that absorbs heat from flue gases. It is the last heat exchanger in a system that attempts to extract as much energy as possible from flue gas before it is released into the atmosphere.

Enthalpy - The total usable energy of a substance. It is often used to gauge the energy of a flow of steam or combustion gases. It is usually has units of Btu/lbm.

Entropy - Energy that is not available to do work. The amount of randomness or disorder of a system. The units of entropy are Btu/lbm-°R.

GLOSSARY

Ethane (C_2H_6) - A gas that comprises a relatively small component of natural gas, but it is often the second most common gas in natural gas. Methane is the main gas in natural gas. Ethane is considered to be a reactive organic compound (ROC) by the Air Resources Board.

Fuel Bound Nitrogen - Nitrogen that is present in a fuel. Any nitrogen in a fuel can form into NOx compounds when the fuel burns.

Fugitive Emissions - The escape of pollutant emissions into the atmosphere from man-made or natural sources. Some examples include emissions of VOCs from leaking storage tanks, valves, flanges, pumps and compressors at refineries or chemical plants; particulates from storage piles; or natural windblown dust.

Gas Turbine - An engine that uses a compressor to draw air into the engine and compress it. Fuel is added to the air and combusted in the combustor. Hot combustion gases exiting the engine turn a turbine which also turns the compressor. The engine's output power can be received from the compressor or turbine side of the engine.

Heat Rate - A parameter which is equivalent to the total energy output of a process (such as a gas turbine) in Btu/hr divided by the energy output in kilowatts. The units of heat rate are therefore usually Btu/kilowatt-hr.

Heat Recovery Steam Generator (HRSG) - A large, somewhat triangular shaped vessel connected to the back end of a gas turbine that contains heat recovery equipment, carbon monoxide catalyst, and SCR catalyst. The heat recovery equipment consists of boiler tubes and boiler drums through which steam is produced for steam injection and/or to run other thermal processes.

Hemoglobin - An oxygen carrying protein that is in the red blood cells. Hemoglobin carries oxygen from the lungs to all the cells throughout the body. Carbon monoxide attaches more strongly to hemoglobin than oxygen. This is why emissions of carbon monoxide are a great concern.

Heterogenous Nucleation - A particle formation mechanism where solid material nucleates or accumulates on the surfaces of previously formed particles. The temperature must be below the dew point temperature of the material for heterogeneous nucleation to occur.

Higher Heating Value (HHV) - The heat released by burning a particular fuel. The higher heating value includes the heat necessary to vaporize the water formed from combustion.

High Pressure Compressor - The last compressor before the combustor. The high pressure compressor increases the pressure of the incoming air to its maximum value.

High Pressure Turbine - The first turbine exhaust gases enter after the combustor in a gas turbine with multiple turbines. The high pressure turbine is exposed to the highest temperatures and pressures.

Homogeneous Nucleation - A particle formation mechanism where vapor phase material nucleates to form new particles. The temperature must be below the dew point temperature of the material for homogeneous nucleation to occur.

Hydrocarbons - Organic compounds of hydrogen and carbon atoms. There is a vast number of these compounds. Some examples include: methane, butane, heptane, octane, benzene, etc. Emissions of volatile hydrocarbons into the atmosphere can lead to the formation of smog in the atmosphere.

Hydrogen Sulfide (H₂S) - An odorous, poisonous, unwanted gas that is encountered in many gas production, oil production, and refining operations. It has a strong rotten egg odor, but it cannot be detected by a person's sense of smell at high concentrations.

Igniter Plug - A device, similar to the spark plug in a reciprocating internal combustion engine, that ignites the air and fuel mixture entering a combustor of a gas turbine.

Immediately Dangerous to Life and Health - A concentration of a chemical, as published by the National Institute for Occupational Safety and Health (NIOSH), that would be immediately dangerous to a person's health and safety upon exposure.

Impulse Turbine - A turbine that absorbs energy by the change in direction of the flow (combustion gases, steam etc.) through the turbine blades. Unlike a reaction turbine, the pressure and speed of the flow through an impulse turbine remain essentially constant.

GLOSSARY

Incomplete Combustion - The burning of fuel and air where the fuel is not completely burned. Incomplete combustion can be caused by too little air or too much fuel in a combustion process. Incomplete combustion results in carbon monoxide emissions.

Intercooler - A heat exchanger that may be utilized before the compressor of a gas turbine. The intercooler cools the air before it is compressed, increasing its density. The intercooler increases the output work of the gas turbine and decreases the amount of work required for compression. An intercooler may typically use a refrigerant or chilled water, which runs through tubes in the intercooler while the air flows on the outside of the tubes.

Internal Energy - All the kinetic and potential energy in the atoms and molecules of a substance. Internal energy is usually in units of Btu/lbm.

Isentropic - A process where the entropy (the amount of energy not available to do work) is constant. A reversible, adiabatic (no heat transfer) process.

Joule Cycle - See Brayton Cycle.

Kerosene - A refined fraction of crude petroleum that is heavier than naphtha, but lighter than gas oil. It has a boiling point between 315 and 450°F.

Kinetic Energy - The energy possessed by an object in motion. Kinetic energy is one half times the mass of the object, times the velocity squared. A gas or a liquid in motion also has kinetic energy.

Lean - An air-fuel mixture that has too much air or not enough fuel.

Lower Explosive Limit (LEL) - The concentration at which a mixture of air and volatile compounds becomes flammable.

Lower Heating Value (LHV) - The heat released when burning a fuel. The lower heating value does not include the heat necessary to vaporize the water produced from combustion, but the higher heating value does.

Low Pressure Compressor - The first compressor in a gas turbine with multiple compressor stages. It compresses air entering the compressor at atmospheric pressure.

Low Pressure Turbine - The last turbine that exhaust gases flow through in a gas turbine with multiple turbines (when there is no power turbine). If there is a power turbine, the low pressure turbine is the turbine ahead of the power turbine.

Mach Number (M) - A parameter which is the velocity of a flow (usually air) divided by the speed of sound at the point in question. The Mach number is used to show if a flow of air is subsonic M < 1, sonic M = 1, or supersonic M > 1.

Manometer - A device used to measure the relative or gage pressure inside a vessel. A manometer has a glass tube that contains water or mercury, measuring the pressure in inches of water or mercury.

Mixed Flow Turbine - A radial-inflow turbine that operates as a centrifugal compressor in reverse. Combustion gases enter the turbine radially and exit axially.

Molecular Weight - The relative weight of atoms or molecules. The weight of one mole of atoms or molecules, one mole being 6.02×10^{23} individual atoms or molecules. The molecular weight of carbon, for example, is 12.

National Ambient Air Quality Standards (NAAQS) - National Ambient Air Quality Standards are developed by EPA pursuant to Section 109 of the Federal Clean Air Act. NAAQS exist for nitrogen oxides, sulfur oxides, particulate matter, ozone, and carbon monoxide.

National Emission Standards for Hazardous Air Pollutants (NESHAPS) - Federal standards for the emissions of toxic compounds.

Natural Gas - Gaseous hydrocarbons made of at least 80% methane and maybe some ethane, propane, and butane.

New Source Performance Standards (NSPS) - Federal regulations from the EPA for new or modified stationary sources. They are located in the Code of Federal Regulations Title 40 Part 60.

GLOSSARY

Nitrogen Oxides (NOx) - A compound of a nitrogen atom and one or more oxygen atoms. These compounds are emissions of combustion processes and can lead to ozone formation (examples: NO = nitrogen oxide; NO₂ = nitrogen dioxide). Most of the NOx from combustion processes is in the form of NO, but NO later forms into NO₂. NO₂ is much more harmful than NO. Nitrous Oxide (N₂O) emissions can also be a concern, but they are a much smaller problem.

Notice of Violation (NOV) - Document issued to a company for violating air pollution regulations.

Open Cycle Gas Turbine - A gas turbine that takes in atmospheric air and rejects air and exhaust gases to the atmosphere. The air is used as the gas turbine's working fluid.

Organic - Of or containing carbon.

Otto Cycle - The theoretical combustion cycle of the spark ignition engine. The parts of the cycle include adiabatic (no heat transfer) compression (in the cylinder from a piston), constant volume heat addition (combustion), adiabatic expansion (work done on the piston) and constant volume heat rejection to the atmosphere.

Ozone (O_3) - A colorless, odorless gas, formed by chemical reactions between hydrocarbons, nitrogen oxides and sunlight, that is irritating and damaging to humans, plants and animals. It is the main component of smog and is California's biggest air pollution problem.

Partial Pressure - The pressure of a gas in a mixture of gases that would be exerted if the gas was by itself.

Particulates - Solid or liquid particles in the air. Smoke, for example, contains particulate matter. Particulates less than 10⁻⁶ m (meters) in diameter are also called PM10. Particles of this size and smaller are of greatest concern because they can easily pass deep into the lungs.

Peaking Turbine - A gas turbine that is run when electrical demand is very high. These high demand periods often occur during the summer months during heat waves.

GLOSSARY

Permit to Operate - A document issued to the owner or operator of pollution generating or control equipment, allowing the owner to use the equipment in a manner to reduce emissions.

Petroleum - Crude oil as it comes from an oil well. Any of the solid, liquid or gaseous hydrocarbons derived from crude oil.

Photochemical - Chemical reactions that are dependent on the energy of sunlight. Ozone, for example, is a photochemical pollutant and needs sunlight to form.

Power Turbine - A turbine that is often retrofitted to aero-derivative gas turbines to convert the kinetic energy from the exhaust gases into mechanical power.

Pressure Ratio - The pressure of the air leaving the compressor of a gas turbine divided by the pressure of the air entering the compressor of a gas turbine.

Primary Air - Air that flows through the holes in the front portion of the liner and into the combustion chamber. Some of the primary air is burned in the combustor.

Prompt NOx - A NOx formation mechanism where NOx is formed in the flames of combustion from hydrocarbons formed during intermediate chemical reactions.

Propane (C_3H_8) - A fuel that is derived from petroleum that is gaseous at atmospheric conditions, but it is easily liquefied. Propane is also liquefied petroleum gas (LPG), which is an alternative fuel.

Psychrometer - A device used to measure dry bulb and wet bulb temperature. It has two thermometers and a handle that allows a person to twirl the device in a rotational motion. The dry bulb thermometer looks like an ordinary thermometer, but the wet bulb thermometer has a gauze on the end. When a wet bulb measurement is taken, the gauze is wetted and the psychrometer is twirled.

GLOSSARY

Psychrometric Chart - A chart with a graphical representation of air and water vapor that contains the following parameters: dry bulb temperature, wet bulb temperature, specific volume, enthalpy, relative humidity, and humidity ratio. Once two parameters are known the others can be determined.

Pump - A device used to add energy to a fluid in order to move the fluid from one location to another. There are generally two types, positive displacement and kinetic.

Radial Inflow Turbine - A turbine that works as an inverse centrifugal compressor. Few gas turbines use this type of turbine. The two types of radial inflow turbines include the cantilever and mixed-flow type. The cantilever is similar to the axial turbine, but gases are directed radially inward to turn the turbine.

Ram Jet - A steady flow combustion engine that works as a gas propulsion device with no compressor or turbine wheels. A ram jet will only begin to produce thrust at velocities over 300 miles/hour.

Reaction Turbine - A reaction turbine is designed with a decrease in cross-sectional area through the passages in between turbine blades. This decrease in area causes the speed and pressure of the combustion gases passing through it to change. The turbine absorbs the energy required to change the velocity of the gases.

Reactive Organic Compound (ROC) - See "volatile organic compound."

Reactive Organic Gas (ROG) - A term used by the Air Resources Board that means the same as volatile organic compound (VOC), but it also includes ethane as a VOC. The EPA definition of VOC does not include ethane.

Reciprocating Internal Combustion Engine - An engine that consists of pistons and cylinders where air and fuel are injected into the engine, compressed by the piston, and ignited by a spark plug. The combustion in the cylinder pushes the cylinder and that energy is transferred to the crankshaft, causing it to rotate.

Regenerator - A heat exchanger that may be used on a gas turbine to increase the thermal efficiency. Hot exhaust gases are passed through the regenerator, while compressed air from the compressor is passed through the regenerator at the same time. Heat is exchanged from the hot exhaust gases to the relatively cooler compressed air, before it enters the combustor through tubes or across other surfaces in the regenerator. The two streams do not mix directly.

Reheater - A reheater works as a second combustor in a gas turbine. After combustion gases leave the turbine, they enter the reheater, additional fuel is added, the air and fuel undergo combustion, and then the gases are expanded through another turbine. The reheater increases the output work of the gas turbine. Afterburners in jet aircraft are essentially reheaters.

Residence Time - The amount of time that fuel and air are within a combustion chamber. This is the amount of time that the fuel and air have to burn.

Rich - An air-fuel mixture that has too much fuel or not enough air.

Ringelmann Chart - A gray to black smoke scale published by the U.S. Bureau of Mines ranging from 0 to 5, where "5" is black smoke with 100% opacity, "4" is 80% opacity, "3" is 60% opacity, "2" is 40% opacity, and "1" is 20% opacity. "1" is the limit in most districts.

Rotor blades - The rotating blades in an axial compressor or turbine.

Scouring - A condition that can adversely affect a catalyst bed, caused by the movement of the hot gas stream wearing down the catalyst over time. The catalyst is sometimes in the form of a coating, so once it wears off, parts of the bed may become useless. This is especially a problem in incinerators.

Secondary Air - Air that flows through the holes toward the back end of the liner. Secondary air helps cool the liner and cool the combustion products by dilution before the gases enter the turbine.

Selective Catalytic Reduction (SCR) - A popular method of controlling NOx compounds in combustion processes. SCR involves injecting ammonia into the exhaust gas before it flows through a catalyst. The catalysts for SCR are very large and are often made with a type of noble metal. NOx compounds are converted to nitrogen and water by SCR.

GLOSSARY

Selective Noncatalytic Reduction (SNCR) - A method used to control NOx compounds by injecting ammonium hydroxide or urea into the flue gas. NOx compound are converted into N_2 and water from the process. SNCR is run at higher temperatures than selective catalytic reduction (SCR) and is not used to control NOx from gas turbines.

Smog - A combination of the word "smoke" and "fog." Pollutants such as ozone, carbon monoxide, particulate matter, nitrogen oxides, and sulfur oxides make up smog.

Source Test - A test performed on pollution generating or control equipment to determine the emissions from it. Source tests have to be conducted on equipment with or without continuous emission monitors to determine the emissions.

Space Velocity - A parameter which is the combined volume flow rate of the inlet gas stream into the catalyst bed of a selective catalytic reduction unit or other device divided by the volume of the catalyst bed. The space velocity is the reciprocal of the residence time.

Specific Heat - The ratio of heat to temperature change of a substance. It is the heat transfer divided by the mass of the substance and the change in temperature or $c = Q/m\Delta T$.³

where:

 $c = Specific Heat (Btu/lbm^{\circ}R)$

Q = Heat transfer (Btu)

m = Mass (lbm)

 ΔT = Temperature Change (degrees Rankine)

Specific Volume - The reciprocal of density. The volume of a substance divided by its mass.

Split Compressor - See twin spool.

Stability - A term that describes the flame in a gas turbine. A stable flame in a gas turbine is necessary for efficient operation. A stable flame will not pulsate and will burn steadily.

Stoichiometric - A situation in combustion where there are exactly enough oxygen molecules to react with the fuel molecules. Combustion processes are usually run with excess oxygen (air), since mixing of fuel and air is not perfect and all the oxygen molecules cannot find fuel molecules to react with during the short time period of combustion.

Subsonic - A flow (usually air) with a Mach number less than one (see Mach number). An air flow where the velocity is less than the speed of sound at the point in question.

Supersonic - A flow (usually air) with a Mach number greater than one (see Mach number). An air flow where the velocity is greater than the speed of sound at the point in question.

Static Pressure - The pressure exerted by stationary air. The pressure energy of a fluid. Static pressure is usually measured in inches of water column.

Stator Blades - Stationary blades in the compressor or turbine section of a gas turbine that are fixed to the casing surrounding the compressor or turbine. Stator blades work to compress air in the compressor or extract energy for the turbine. The stator blades change the direction of the flow of air or exhaust gases so it will have the correct angle of attack. Some compressors are equipped with variable stator vanes which can rotate to change the angle of attack.

Sulfur Dioxide (SO₂) - A pollutant that comes from combustion processes using fuels with sulfur in them, and other industrial operations. It has a sharp, pungent smell.

Sulfur Oxides (SOx) - Sulfur compounds SO₂, SO₃, etc. See "sulfur dioxide."

Superheated Steam - Steam that has been heated above its boiling point. Steam that is completely gaseous and does not consist of any condensed water vapor.

Symmetrical Stage - A rotor and a fixed stator stage, where the pressure rise through the moving blades is designed to be equal to the pressure rise through the stationary blades at any given radial distance from the compressor axis.⁴

GLOSSARY

Synergistic Effect - When the combined health effects of more than one pollutant or substance is worse than the effect of the pollutants by themselves. Sulfur dioxide, for example, has worse health effects when it is combined with particulate matter. Sulfur dioxide health effects are even worse when combined with moisture.

Thermal Aging - The gradual recrystallization of noble metal catalyst materials caused by the high temperatures that the catalyst bed is continually exposed to. It is an unavoidable gradual deterioration of the catalyst.

Thermal Burnout - The volatilization of the compounds from the catalyst bed that make up a catalyst. It is caused by excessively high temperatures. This problem occurs in incinerators and other catalysts.

Thermal Efficiency - The output work of a system or engine divided by the supplied energy (output work/input energy). It is essentially a measure of fuel economy.

Thermal NOx - Nitrogen oxides formed from the nitrogen present in atmospheric air. At higher combustion temperatures, the nitrogen in the air will react (burn).

Turbine - A device used to convert the kinetic energy from a gas stream into mechanical energy. The two main types of turbines are the radial inflow type and the axial flow type. Most turbines used on gas turbines are the axial type, and the types of axial turbines include the reaction turbine, impulse turbine, and the reaction-impulse turbine.

Turbofan Engine - A gas turbine engine where the compressor is equipped with a enlarged fan that not only compresses air entering the engine, but provides propulsion for the aircraft. The thrust from the exhaust gases expanding out the back end of the engine also provide a percentage of the thrust.

Turbojet Engine - A type of gas turbine engine that only utilizes the thrust force produced from expanding exhaust gases from the back end of the engine for propulsion.

Turboprop Engine - A gas turbine engine where the turbine runs the compressor and an output shaft connected to a propeller. A gear train is used to reduce the revolutions per minute of the turbine output to the appropriate propeller speed.

Turboshaft Engine - The type of gas turbine engine used for propulsion for helicopters. The turbine in the gas turbine runs the compressor and the output shaft. A gear train reduces the output shaft revolutions per minute so the helicopter blades rotate at the appropriate speed.

Twin Spool - A name describing a gas turbine with two separate compressors and turbines, including a low pressure compressor and a high pressure compressor, and low pressure turbine and high pressure turbine.

Unsymmetrical Stage - A rotor and stationary stator stage where the ratio of pressure rise through the rotor blades and stator blades is constant along the blade length.⁵

Vapor Pressure - The pressure exerted by a vapor that is in equilibrium with its liquid state.

Variance - Permission given to a facility by an APCD or AQMD to legally pollute beyond regulated limits because of a breakdown or other condition.

Velocity Pressure - The pressure exerted due to the motion of an air stream.

Volatile - A substance that evaporates at a high rate at a low temperature.

Volatile Organic Compound (VOC) - Any compound with at least one carbon atom except: methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides, metallic carbonates, ammonium carbonate, methylene chloride,

1,1,1 trichloroethane (methyl chloroform),

GLOSSARY

1,1,2 trichlorotrifluoroethane (CFC-113), trichlorofluoromethane (CFC-11), dichlorodifluoromethane (CFC-12), dichlorotetrafluoroethane (CFC-114), chloropentafluoroethane (CFC-115), trifluoromethane (CFC-23), HCFC-123 (dichlorotrifluoroethane), HCFC-134a (tetrafluoroethane), HCFC-141b (dichlorofluoroethane), HCFC-142b (chlorodifluoroethane), and chlorodifluoromethane (CFC-22).

The exact listing of compounds may vary. Some districts use the terms precursor or reactive organic compounds to denote VOC. As a note, many of these compounds which are listed as exempt compounds may contribute to upper atmosphere ozone destruction. Other exempt compounds are being investigated as possible toxic air contaminants. Finally, carbon dioxide is considered to be a "greenhouse gas" which may contribute to global warming, and carbon monoxide is a primary pollutant.

Vortex Stage - A rotor and stator stage where the angular momentum acting on any given fluid particle in the radial direction is constant.6

Wet Bulb Temperature - The temperature indicated by a wet bulb thermometer on a psychrometer. The temperature of atmospheric air that has gone through an adiabatic saturation process (adiabatic means no heat transfer). Adiabatic saturation is the process that occurs when a psychrometer is twirled, causing the water in the gauze of the wet bulb thermometer to evaporate. The energy of evaporation comes from the atmospheric air.

Work Ratio - A parameter which is the net output work produced by a gas turbine, divided by the total work of the turbine.

Zeldovich Mechanism - The chemical reactions that produce NOx compounds.

INDEX

A Acid Rain 400 - 12 Single Can 200 - 42 Aero-derivative Gas Turbines 200 - 31, 200 - 68 Sore Thumb 200 - 42 Afterburner 200 - 62 Compliance Assistance Program 100 - 1 Air Heater 200 - 26 Compression Ratio 200 - 8 Air Rate 200 - 22 Compressors 200 - 31 Aircraft 100 - 7 Axial 200 - 35 Ammonia 300 - 29, 500 - 9 Centrifugal 200 - 32 Ammonia Slip 300 - 36 Positive Displacement 200 - 32 Ammonium Bisulfate 300 - 34 Condenser 200 - 59 Ammonium Salts 300 - 34 Continuous Emission Monitors 300 -Ammonium Sulfate 300 - 34 51, 400 - 15, 500 - 11 Angle of Attack 200 - 39 Cooling Tower 200 - 56 Authority to Construct 400 - 30 Cross-over Tubes 200 - 42 Axial-flow Turbine 200 - 48 D В Deaerator 200 - 57 Best Available Control Technology 400 - 37 Density 200 - 3 Brayton Cycle 200 - 1, 200 - 4 Diesel Cycle 200 - 4 Breakdown Rules 400 - 30 Diffusion Flame 200 - 57 Diluent Injection 300 - 21 C District Regulations 400 - 18 Dual Cycle 200 - 4, 200 - 59 California Air Resources Board 100 - 1 California Clean Air Act 400 - 18 Duct Burners 200 - 57, 300 - 8, 300 - 48 California Code of Regulations 400 - 17 E California Environmental Protection Agency 100 - 1 California Health and Safety Code 400 - 17 Economizer 200 - 57 Cantilever 200 - 49 Emergency Power 100 - 7 Carbon Monoxide 300 - 9, 300 - 22, 300 - 49, 500 - 9 Enthalpy 200 - 3 Catalyst 300 - 29 Entropy 200 - 3 Catalytic Combustion 300 - 47 Environmental Protection Agency 300 -Closed Gas Turbine Cycle 200 - 26 1, 400 - 1 Coal Gas 300 - 56 EPA Method 9 400 - 27, 500 - 6 Code of Federal Regulations 400 - 2 Equipment Breakdown Provisions 400 -Cogeneration 100 - 6 30 Combined Cycle 200 - 59 Equipment Check 500 - 5 Combustors 200 - 42 Equivalence Ratio 300 - 6 Annular 200 - 42, 200 - 45 Ericsson 200 - 1 Can 200 - 42 Ericsson Cycle 200 - 4 Can-annular 200 - 42 Ethane 300 - 1 Green Thumb 200 - 42 External Combustion Engines 100 - 5 Liner 200 - 45

Index - 1

Silo 200 - 42

F L Federal Clean Air Act 400 - 1 Lean 300 - 6 Federal Regulations 400 - 2 Lean Premixed Combustors 300 - 41 Feedwater Pumps 200 - 57 Levels of Inspection 500 - 3 File Review 500 - 4 Low Pressure Compressor 200 - 29 Fixed Stator Vanes 200 - 40 Low Pressure Turbine 200 - 29 Flame Stability 200 - 47 Lower Heating Value 400 - 3 Flow Energy 200 - 3 M Fuel Bound Nitrogen 300 - 3 Fugitive Dust 300 - 14 Mach Number 200 - 62, 200 - 64 Mass 200 - 2 G Methane 300 - 1 Gas Turbines 100 - 4 Methanol 300 - 55 Gravitational Constant 200 - 2 Mixed-flow 200 - 49 Modifications 400 - 29 Н N Health and Safety Code 400 - 17, 400 - 28, 400 -Natural Gas 300 - 1 Heat Rate 300 - 25 NESHAPS 400 - 11 Heat Recovery Steam Generator 200 - 54 New Source Review 400 - 37 Heavy Duty Engines 200 - 31, 200 - 68 Newton's Laws of Motion 200 - 58 Nitrogen Dioxide 300 - 1, 300 - 8 Hemoglobin 300 - 10 High Pressure Compressor 200 - 29 Nitrogen Oxides 300 - 1 High Pressure Turbine 200 - 29 Notice of Violation 400 - 19 Higher Heating Value 400 - 3 Nozzle Guide Vanes 200 - 50 HRSG 300 - 33 NSPS 400 - 1 Hydrocarbons 300 - 12 О Offsets 400 - 38 Impulse Turbine 200 - 49 Otto Cycle 200 - 4 Incomplete Combustion 300 - 9 Ozone 300 - 12 Industrial Engines 200 - 31, 200 - 68 Inspection and Maintenance (I&M) 500 - 1 Intercooling 200 - 16 Particulate Matter 300 - 14 Internal Combustion Engines 100 - 5 Permits to Operate 400 - 29, 500 - 1, 500 - 4 Internal Energy 200 - 3 Petroleum Distillates 300 - 1 International Standards Organization (ISO) 400 - 4 Pitch 300 - 30 Precooler 200 - 26 J Pressure 200 - 2 Jet Propulsion 200 - 58 Pressure Ratio 200 - 8, 200 - 37 Joule 200 - 1 Prevention of Significant Deterioration 400 -Joule Cycle 200 - 4 17 Joule's Constant 200 - 3 Primary Zone 200 - 45 Prompt NOx 300 - 3 K Public Utility Regulatory Policies Act 100 - 6

Kelvin 200 - 2

R	Superheater 200 - 57	
Radial Inflow Turbine 200 - 48 Ram Jet 200 - 67	Supersonic 200 - 62 Symmetrical Stage 200 - 40	
Rankine 200 - 2	T	
Reaction Turbine 200 - 49		
Reaction-impulse Turbine 200 - 49	Temperature 200 - 2	
Reactive Organic Compound 300 - 1	Thermal NOx 300 - 2, 300 - 40	
Reburning 300 - 48	Three T's of Combustion 300 - 5	
Reciprocating Engines 100 - 4	Title V 400 - 17	
Recuperators 200 - 14	Turbines 200 - 48 Axial-flow Turbine 200 - 48	
Refineries 100 - 6	Cantilever 200 - 49	
Regenerators 200 - 14	Impulse 200 - 49	
Regulation Review 500 - 4	Mixed-flow 200 - 49	
Reheat 200 - 20	Radial Inflow Turbine 200 - 48	
Residence Time 300 - 5, 300 - 30, 300 - 40	Reaction 200 - 49	
Rich 300 - 6	Reaction-impulse Turbine 200 - 49	
Ringelmann Chart 400 - 27, 500 - 6	Turbofan Engine 200 - 65	
Rotor Blades 200 - 35	Turbojet Engine 200 - 61	
RQL Combustor 300 - 46	Turboprop 200 - 63	
S	Turboshaft Engine 200 - 65	
G 1 (* G (1 (* B 1 (* (GGB) 200 20 50	Twin Spool Engine 200 - 29	
Selective Catalytic Reduction (SCR) 300 - 28, 50 - 9	ັ ບ	
	•	
Selective Noncatalytic Reduction 300 - 39		
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4	Unsymmetrical Stage 200 - 40	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42		
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6	Unsymmetrical Stage 200 - 40	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31	Unsymmetrical Stage 200 - 40	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1 Stirling Cycle 200 - 4	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28 Work Ratio 200 - 23 X	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1 Stirling Cycle 200 - 4 Stoichiometric 300 - 6	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28 Work Ratio 200 - 23 X Xonon Flameless Combustor 300 - 47	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1 Stirling Cycle 200 - 4 Stoichiometric 300 - 6 Subsonic 200 - 62	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28 Work Ratio 200 - 23 X	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1 Stirling Cycle 200 - 4 Stoichiometric 300 - 6	Unsymmetrical Stage 200 - 40 V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28 Work Ratio 200 - 23 X Xonon Flameless Combustor 300 - 47	
Selective Noncatalytic Reduction 300 - 39 Simple Cycle Gas Turbine 400 - 4 Sore Thumb Combustor 200 - 42 Source Testing 500 - 2, 500 - 6 SOx-NOx-ROx-Box 300 - 31 Specific Heat 200 - 3 Specific Volume 200 - 3 Split Compressor Engine 200 - 29 Stabilizer Casing 200 - 57 Staged Combustor 300 - 46 Standard Temperature and Pressure (STP) 200 - 2 State Implementation Plan 400 - 18 State Regulations 400 - 17 Stationary Gas Turbines 100 - 6, 400 - 4 Stator Blades 200 - 35 Steam Injection 300 - 21, 500 - 9 Stirling 200 - 1 Stirling Cycle 200 - 4 Stoichiometric 300 - 6 Subsonic 200 - 62 Sulfur Dioxide 300 - 11, 400 - 8, 400 - 14	V Vanadium Pentoxide 300 - 30 Variable Stator Vanes 200 - 39 Variances 400 - 33 Visible Emissions 400 - 27, 500 - 6 Volatile Organic Compounds 300 - 1, 300 - 12 Vortex Stage 200 - 40 W Water Injection 200 - 26, 300 - 21, 500 - 9 Water Treatment 300 - 24 Water-in-oil Emulsion Injection 300 - 28 Work Ratio 200 - 23 X Xonon Flameless Combustor 300 - 47 Z	

June 1996 Index - 3

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